BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number:

GENERATION MARKET POWER AND: RM04-7-000

AFFILIATE ABUSE :

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, N.E.

Room 2C

Washington, D.C.

Thursday, January 27, 2005

The above-entitled matter came on for technical conference, pursuant to notice, at 9:10 a.m., Steve Rodgers, presiding.

P R O C E E D I N G S

(9:10 a.m.)

MR. RODGERS: Why don't we go ahead and get started this morning. I'm going to ask our panelists on the morning panel to please come and take their seats up at the table.

While they're doing that, I'm just going to mention, to kick us off, that the purpose of this two-day conference is to address issues associated with the generation market power screen that the Commission has, as well as the affiliate abuse prong that the Commission has, which are two of the four prongs the Commission uses as part of its current four-part test to assess the existence of market power for purposes of determining qualification for market-based rate authorization.

The first day of the conference we'll consider when and, if so, to what extent the Commission should modify the interim generation market power screens adopted by the Commission in orders issued in July and April of last year as well as the appropriate mitigation for those that are found to have market power. Tomorrow's conference will address issues such as affiliate abuse, reciprocal dealing and the competitive solicitation process.

Each panelist has been asked to give opening remarks and we will proceed directly from one panelist to the next without questions in between. After all the panelists have spoken, we will have questions and responses between the staff, the panelists and the Commissioners and panelists. I very much encourage the panelists themselves, during that time, to comment on what other panelists have had to say.

At the end of each session, this morning's session and this afternoon's session, there will be an opportunity for an open microphone comment from the audience. So, if you're interested in that, there's microphones near the front of the room on either side. And I encourage you to come forward and share your comments and questions at that time. If you have questions that you wish to ask when we get into the Q&A part of the panel, I encourage you to take your temp card and just hold it up on the side. I'll recognize you as soon as I can.

Without further ado then, why don't we introduce this morning's first panelist who is Louis Jahn, Director of Wholesale Market Policy with the Edison Electric Institute.

Welcome, Louis.

MR. JAHN: Thank you, Steve.

Good morning. I'm Louis Jahn, Director of Wholesale Market Policy with the Edison Electric Institute. I'm appearing before the Commission today on behalf of the

Institute and on behalf of the Alliance of Energy Suppliers, which is a division of EEI that represents power suppliers.

The purpose of my testimony today is to present to the Commission a new market power screen that EEI proposes be adopted by the Commission for the purpose of determining whether an MD or applicant does or does not possess market power. This new market power screen assesses whether the applicant actually does or does not possess market power through an analysis of the actual state of competition in the wholesale marketplace.

This assessment process focuses on a determination of the relationship between the wholesale loads that were actually seeking competitive supply alternatives, i.e., contestable loads and competitive generation resources that were available to serve those loads. This proposal, which is termed a historical contestable load analysis, is attached as Appendix A to my written testimony.

Let me first address the question as to why EEI believes that there is a need for a new generation market power screen. Both the pivotal supplier and market power screen were designed primarily by the Commission to function as indicative screens for the purpose of identifying those MBR applications that would require a more detailed scrutiny by the Commission to determine whether the applicant does or does not possess market power.

EEI recognizes that there is a definite need for an indicative screen, given the volume of MBR applications that come before the Commission. However, as with any indicative screen, both screens have had to trade a certain degree of analytical accuracy for simplicity of preparation as well as a limitation on the scope of the data input required to prepare the screen.

This analytical tradeoff process, however, has been particularly significant with regard to the market share screen. For example, the market share screen does not consider the relationship of total wholesale capacity to total market demand of assessing whether the applicant does or does not possess market power.

The analytical tradeoffs in the market share screen have created the potential for a significant false positive problem associated with the use of this screen. By that I mean that the market share screen will incorrectly indicate that a MBR application has market power.

In support of this concern, EEI would note that non-RTO utilities are currently experiencing a failure rate of approximately 70 percent for the market share screens within their control areas in the MBR filings that have been made to date. This contrasts with the failure rate of approximately 9 percent for the pivotal supplier screen.

This result indicates to us that a significant false positive problem may be associated with this screen, particularly, in light of the results of the supplemental analyses that have been filed by some companies failing the market share screen. These analyses appear to demonstrate that the applicant does not possess market power within their control.

From EEI's perspective, while there is a need to address the potential false positive problem associated with the continued use of the market share screen for indicative purposes, EEI also believes there is a need at this time to develop a market power screen that would determine whether the applicant does or does not possess market power based upon an assessment of the actual state of competition in the marketplace. This is the purpose of the contestable load analysis that I'm presenting you today.

Let me now make a few brief comments on the proposed preparation guidelines for the contestable load analysis, which is attached as Appendix A to my written testimony that I provided you today.

Guidelines 1 to 3 require the applicant to identify the relevant product and markets that will be used in the analysis. Note that the applicant can define multiple product markets for use in the analysis, for example, on-peak/off-peaks, short-term/long-term. Note further that, while the applicant is required to file an analysis based upon historical data, which is consistent with the April order, the applicant also has an option to file a forward-looking analysis.

A forward-looking analysis would be particularly important if the applicant's assets position or market conditions are expected to change significantly in the market. This additional option would address some of the issues the Commission is currently addressing in the change of status RMO-414 proceeding.

Guideline 4 requires the applicant to identify all contestable loads. Note that under our guidelines the applicant is given the opportunity to develop the specific methodology that the applicant will use to identify the contestable loads. For example, the applicant might rely upon an analysis of RFPs within the control area. Alternatively, an applicant might identify contestable loads through an analysis of the power supply portfolios of the wholesale customers within the control areas.

Guidelines 5 to 7 require the applicant to identify potential competitive suppliers in the market, to identify the total uncommitted capacity that would have been available to compete for the contestable loads and, finally, to determine what portion of that total uncommitted wholesale capacity could have been imported into the relevant market.

For example, an applicant might choose to develop an estimate of uncommitted wholesale capacity on an hourly basis through a load shape analysis that incorporates hourly data. In other words, this is going down the roads that we think you should be looking at, for example, uncommitted wholesale energy.

Guideline 8 requires the applicant to provide a demonstration that transmission constraints did not limit access by the contestable loads to the generation resources. This requirement could be addressed by the applicant, for example, by an analysis of transmission congestion data.

Finally, Guidelines 9 and 10 establish the criteria that EEI is proposing for the applicant to pass the contestable load analysis. Under the proposed guidelines, if total competitive generation resources are at least twice the contestable load, the applicant will be deemed to have passed the analysis for the specified product and seasons. In addition, the applicant would have to provide a demonstration to the Commission that the competitive generation resources were not unduly concentrated among competitive suppliers.

Let me now address how the EEI proposes that the Commission use this contestable load analysis. EEI proposes that this analysis be filed at the time the MBR applicant makes its initial filing for MBR authorization or reviewed by the Commission for determining whether the applicant does or does not possess market power. If the analysis determines that the applicant possess an absence of market power, a rebuttal presumption would be to establish the applicant does not possess market power and therefore there would be no need to initiate a 206 proceeding.

In conclusion, EEI believes that there is a need, at this point, to implement a market power screen that would provide the Commission with a more accurate determination of whether the applicant does or does not possess market power based upon an assessment of the actual state of competition in the marketplace. From EEI's perspective, that determination process should focus on an analysis of the relationship between contestable loads and competitive generation resources in the market. This is the conceptional premise of the basis for EEI's contestable load analysis.

Thank you for the opportunity that you have given EEI to present our proposal to you today. I look forward to answering any questions you may have later.

MR. RODGERS: Thank you very much. We appreciate that.

Let me next turn to Jim Bushnell, the Research Director of the University of California Energy Institute.

Welcome.

MR. BUSHNELL: Thank you. I'd like to thank the Commission for the opportunity to, again, opine on horizonal electric power screens, a subject near and dear to my heart, which means there's probably something wrong with me.

The Commission has made a lot of progress in this area. The types of things that are being talked about now certainly incorporate a lot more careful thinking in terms of where we've moved from. But, in a way, the progress that's been made so far only makes it more frustrating for me to see the serious problems that remain with the interim generation market power screens.

The interim screens create unnecessary risks for both false positive and false negative indications of market power, which I imagine you'll be hearing about from many other people today. The spirit of the changes embodied in the development of the interim screens could be improved upon by embracing screens that are just more fundamentally based on economic oligopoly models. The phrase "computer models" has been used to describe these kinds of models, but the fact is that a screen-based oligopoly model could be implemented in a way that really would require no more computing power than the types of formula we've been talking about.

It's just critical for the screens to focus on the key question that these screens are designed to answer, which is, if an individual firm, the firm of interest, tries to raise prices by reducing output, would it find it profitable to do so and what would the impact on the market be? This is the question that concentration methods were intended to answer. You can see the big firms that can't replace that output. There are certainly cases where you could imagine imports or something else making up for the output of that large firm. Conversely, a small firm in a tight market that reduces output could easily find that no other firm could replace its output.

This is a fact the Commission recognized when it adopted the SMA screen. You want to account for the fact that even a firm with small market share could have market power if it were a pivotal supplier in the market. But a pivotal supplier is only the most extreme condition under which market power could be found. This indicates two, three or even four firms could find it unilaterally profitable to reduce output in the market in order to raise prices.

What a market power screen really needs to capture is this notion of residual demand based by suppliers. The demand of the output of that specific firm which takes into account both the demand in the market and the supply from all the other competitors that that supplier might face. In a way the SMA is a very crude attempt to measure the residual demand of the firm, but implicitly it assumes that the marginal cost of all the other firms are zero. There's no market power until the point where these other firms exhaust their capacity.

Why not use the actual costs of the other firms in the market? Reasonable data are publicly available. Otherwise, you'll almost certainly miss circumstances where a firm could raise prices because it has high-cost competitors rather than just capacity-constrained competitors. This is one way in which the interim screens might read false negatives. The other is that the focus is too much on single unilateral market power in the market.

Now there are problems with false positives, also. They will stem largely from the fact that the interim measures do not properly account for supply contracts and retail obligations of firms. You have to go through the logic. Why would a firm want to pull capacity off the market? Well, it does so when it can sell its remaining output at high prices. But, if it's already committed that output at a pre-set contract price, or under some form of retail rate obligation, then there's no point in trying to raise the wholesale price. It reaps no benefit from the fact that it's selling its remaining output at a pre-set price.

In trying to measure the risk of firms exercising market power, it's critically important to try to capture that net wholesale position as accurately as possible. This is where the interim screens really fall short. The measures in that position are completely ad hoc and just as worrying as the fact that the ad hoc measure of net position is implemented in a pretty ad hoc way.

Concentration measures and even pivotal supply measures just don't accommodate consideration of net position very well. You can't just plug net position into a formula. That really makes sense if you try to develop a modified concentration measure that utilizes net position in a way that is consistent with underlying economic power the way the original concentration methods are consistent with an underlying model.

Hendrickson, Preston and McAfee have been working on a modified HHI that incorporates the net position of firms that are integrated, for example. In this context it makes much more sense just to use the underlying economic model of firm behavior directly. You just plug the net position of a firm into a oligopoly model and it makes sense.

I've been working on the oligopoly model in electricity markets for a long. And, over the last couple of years, I've discovered something somewhat surprising.

They actually work. They work reasonably well. They produce more accurate and more rich and more useful information than any concentration of pivotal supply model could. We're able to recreate market outcomes, backcasting markets in several electricity markets really well with a rather basic Cornell model. The key really is worrying about a lot of specific supply cost details -- getting that retail contract obligations as right as you can.

The triennial review of market-based rate authority seems to me to be the prefect application for an oligopoly model. In the merger context, you'll want to worry about contracts. You want to worry about long-term obligations, but you don't know what's going to happen when those contracts expire. With market-based rate authority, the applicant could reduce wholesale and retail price commitments and apply for the duration of the authorities -- say three years -- and have the supply toward this netting out of the wholesale market position. Among other things, this would help encourage suppliers to sign up their excess capacity under long-term contracts and hopefully provide a counter-balance to a resource adequacy requirements that are placing the same kind of pressure on buyers to sign long-term contracts.

In closing, to me, none of the arguments against using computer oligopoly models are very persuasive. The informational computational requirements really are comparable to those in the existing screens that are being talked about. The theoretical foundation is much stronger and now there is some empirical evidence that suggest that they're pretty good at identifying potential trouble spots as opposed to clear cases where the existing screens have created problems.

I think we've tended to get bogged down in trying to make these oligopoly models as accurate as possible and gotten hung up in debate about the details about specific things. I think we need to think about ways in which simple oligopoly models can be made to be consistent with the principles of trying to capture capacity costs and net position in a way that's consistent with economic theory and I think that would be a big improvement over what the interim screens are trying to do. Thank you.

MR. RODGERS: Thank you, Dr. Bushnell. We appreciate that.

Why don't we next turn to our next panelist, Steve Henderson, the Vice President of Charles River Associates, who has been asked to appear here today on behalf of Entergy Corporation. Welcome.

MR. HENDERSON: Thank you. Thanks, Steve. I'd like to thank the Commission for the opportunity to be here.

I'm appearing on behalf of Entergy companies.

What I'd like to do is focus on the first question asked of this panel. I do think it's appropriate to use two indicative screens. I don't see anything wrong with that. But I want to suggest that the screens are flawed and need to be modified.

The primary problems that I see are measuring native load correctly, both in the screens and in the subsequent delivery price test and also the need to use some sort of measure of economic capacity. There are some other things we could talk about if we have time, like nameplate capacity and some other things. But, in formal discussions with staff, Entergy has been asked how it would suggest modifying the screens. So that's basically my topic today.

This is what I would suggest. Entergy's first recommendation would be to revise the pivotal supplier screen. I'd take the 714 hourly load data and I'd divide it into two parts -- identify the native load portion of that and everything else. Native load would be load that has an obligation to serve either state-regulated retail load or cost-based wholesale requirements -- full requirements or partial requirements load. I would do the pivotal supplier screen only for the peak period, which is the current practice -- no change there.

Then I'd make the following calculation for the applicant and each rival. I'd provide full credit for the native load during the peak period instead of using the current practice of the average daily peak, which, in my view, is an inaccurate proxy. I'd take that measure of native load and subtract it from peak generation capacity. If the difference is positive, it's a measure of uncommitted capacity. If it's negative, it's a measure of the amount of demand which is on net, as it were. That calculation would be done for the applicant and each rival separately.

Some of the positive differences would be a measure of the amount of rival uncommitted capacity internal to the control area and a sum of the negative differences would be a measure of the amount of unmet demand inside of a control area. That unmet load, unmet demand would replace the current wholesale market-load measure, which, in my view, is an inaccurate proxy.

To the internal rival, uncommitted capacity measure, I would add the peak seasonal imports from the simultaneous import study. That would be adjusted for the availability of first tier uncommitted capacity. I would not -- if I were doing this test correctly, I would not include the include the applicant's external generation. That is, external to the control area. Nor would I -- if there were firm transmission reservation in support of that to bring the applicant's external generation into the control area, I would not deduct those transmission reservations from the simultaneous import capability on the grounds that the hypothetical and the pivotal supplier test is basically asking the question, can rivals supply the demand? Can the applicant require load to buy from it, meaning that rivals cannot make the supply? If an applicant tried to do that by withholding the external generation, that external generation could simply be replaced by external rival generation over the same pipeline coming in over the same transmission capacity.

The only way it would make sense to do that deduction is if you went beyond the pure generation market power screen and said I have transmission market power. There's a withholding of the transmission in addition to the withholding of the generation. So, as long as that's pure generation market power screen, I would not make that adjustment. Then, if the total amount of rival and committed capacity computed that way exceeds the unmet load, the applicant is not a pivotal supplier in the peak period and would pass that screen. That's how I would revise the first one.

Entergy's second recommendation would be to revise the market share screen. This one has a bit more extensive revision than I would suggest. As to totaling that output, the market share screen is conducted for four seasons. Three of those four seasons are non-peak seasons.

That creates its own problem. If you're going to conduct an economic capacity -- market share screen for each of the four seasons, I suggest that you need to look at economic capacity. I would start off, once again, by doing the following application for the applicant and each rival. I'd provide full credit for the peak native load in each of the seasons. That would be instead of the current practice that uses the minimum peak seasonal daily peak, which is an inaccurate proxy.

For each of the four seasonal peaks, I would find an appropriate measure of the market clearing price and then find a price benchmark -- I'm not standing by this number -- say 120 percent of that. This is kind of similar to the delivery price test. Market clearing price -- take 120 percent of that and that becomes the pricing benchmark. You could use data like from LMP markets or system lambda data from the 714 or power markets -- week, daily -- to get those market clearing prices. I'd construct a simple stacking model of the internal generation and use that price benchmark, that 120 percent, to identify the economic capacity of the applicant and each of the rivals.

From that I would subtract the peak seasonal native load in the first step. If that difference is positive -- and this would be done for each entity in the market. If that difference is positive, it's a measure of uncommitted economic capacity. For this test the negative numbers don't matter. For the rivals, you have some most positive entries and use that as a measure of the internal rival economic capacity. That would be adjusted for operating reserve and planned outages, as is the current practice. I didn't mention that that same operating reserve planning adjustment will be done in the pivotal supplier test as is the current practice, also.

I would add seasonal imports from the simultaneous import study on this one. I would approach this one differently. If the applicant has external to the control area generation, I would attribute that to the applicant. if he has transmission reservations to delivery, I would deduct that from the simultaneous import limit in making this calculation.

This test is a small shot. The question that's being asked is, what's a snapshot of the market share and it's appropriate to account for the applicant's external generation. The question is different than in the pivotal supplier test.

Having done all that, I would find the applicant's share of the total economic uncommitted capacity if it's less than 20 percent applicant would pass that -- each season would pass that. If the applicant fails either of those revised tests, I would do the same thing that the

Commission currently does and allow the applicant the option of providing a delivered price test as additional review.

To make a couple of points -- it's kind of a "by the way" point -- what I'm suggesting you do with the hourly load data is really no more complicated than what is currently required for the screen. At least, in my firm, our practice is the best way to do what you currently require is to go get that 8760 load data and manipulate it. We have to do that already.

What I'm suggesting is no more complicated than that. You do have to divide that between native load and non-native load. That's an additional complication. That's important. The addition of a simple stocking model does go beyond what the current practice is. That is a step that's a bit more complicated. I don't view that as a difficult step, though. Most practitioners have models like that that are currently available. We certainly do.

I would not use nameplate capacity. We can talk about that in the Q&A if you want to. I'd do some sort of seasonal dependable capacity.

Finally, I recommend that, if an applicant fails the proposed revised screening analysis and elects to provide a delivered price test, that you take three things into consideration. First, I suggest that you only look at available economic capacity in that delivered price test.

Available economic capacity is a term of art, therefore, uncommitted economic capacity, as it were, that consistent with providing the additional review about the screening failure, which, by definition, have involved measures that accounted for native load.

Secondly, if you're going to do that delivered price test, the pivotal supplier piece of that test needs to be done only for the single highest peak period. The whole concept of anybody being a pivotal supplier in a non-peak period is just simply illogical. It doesn't make any sense. As a practitioner, I don't know what to do with that.

Thirdly, market concentration ratios, in my view, such as HHI, are really inappropriate for the purpose of this kind of analysis that the screen has been set up for, which is when you're reviewing the application of a single applicant, our basis message to you today is to study wholesale electricity markets requires separating the wheat from the chaff; in this case, separating the capacity and load that's in the wholesale market and subject to market price risks from the capacity and load that's not in that position.

The chaff that needs to be removed is the capacity that's committed to native load. And, if you're going to study non-peak periods, off-peak periods, it's the uneconomic capacity.

If one is going to study uncommitted capacity, we necessarily must remove the committed capacity from the analysis, and to do so requires an accounting of native load. Such load does not pay market-based prices in the first place. And, if one is going to study non-peak periods, you necessarily must remove the economic capacity that's not in the market. It's just simply not possible to raise market prices by withholding generation that's not in the market in the first place.

That's basically the message I'd like to leave with you. I appreciate very much the opportunity to speak to you.

MR. RODGERS: Thank you very much, Steve. We appreciate your coming, too.

Let's next turn to Julia Frayer, the Managing Director of the London Economics International Corporation. Thank you.

MS. FRAYER: Thank you. Good morning, ladies and gentlemen and Commissioners.

First, I would like to thank you for offering me the opportunity to be here today. As you mentioned, I'm Managing Director of London Economics, an international energy consulting firm, where I direct many of the company's engagements involving market power analysis, strategic bidding and simulation modeling and market design with respect to market power issues and regulation.

Given my background as an economist and consultant for energy companies, market institutions and regulators, I would like to speak to you today about my experiences in applying and working with the horizonal market power test required under Section 203 of the Federal Power Act and the interim generation market power screens adopted by the Commission in their April 14, 2004 order.

I would also like to speak today about possible avenues for further refinement of these market power tests given best practices from energy sectors abroad and the experience with other industries.

Before I begin however, I would like to note that the opinions I express here today are based on my own personal views and are not necessarily reflective of the corporate policies of London Economics or the views of our clients.

I strongly believe that the successful evolution of U.S. power markets requires a stable, well-accepted and adaptable platform for market to power monitoring, not only for safeguard for consumers, but also for market participants.

Market participants, generators, marketers, suppliers need a clear set of commercially reasonable guidelines surrounding market power which they can use to make business decisions. In order for market participants to be able to react sensibly to these guidelines, they need to know in advance what is expected of them. More over, they should not be forced to cope with inconsistent policies. Inconsistency between federal institutions, or between federal and state regulators, will deter industry evolution and hamper development. That's sort of by way of introduction.

That brings me to my initial fundamental question. What is market power? I want to just repeat that so that we have a starting point. The U.S. Department of Justice and Federal Trade Commission horizonal merger guidelines describe market power as, and I quote, "the ability to profitably maintain prices above competitive levels for a significant period of time."

As a practitioner of conducting market power analysis in this industry and others, I find that this definition presents two very important elements for market power policy. First, I note that the ability to exercise market power is expressed in terms of price. I will come back to this.

The second element that I would like to note is the notion of a significant period of time. This idea of a significant period of time permeates throughout market power analysis, starting with the market definition stage. The market power test that we apply must be based on the robust definition of the market. That definition has four key dimensions -- function, geography, product and time.

I understand that the question of geographical dimension is going to be discussed in this afternoon's panel session, so I won't cover that this morning. But I would be remiss not to address critically the product dimension. That is relevant to item E on the agency for this panel.

Item E asks should the generation market power screens be extended to cover capacity and generation-based ancillary services such as reserves and regulations. I would like to suggest the following hypothesis. All these services -- energy, capacity, ancillary services -- are, in fact, part of a single market for wholesale electricity based on my direct observations. From markets there is substantial evidence that such services are treated as substitutes by suppliers and, to some degree, are substitutes on the demand side. The hypothesis can and should be further tested using a range of well-accepted, rigorous techniques for market definition.

If the hypothesis is proved, and I'm making no assumptions about it right now, on the basis of rigorous analysis, then the market power test, by definition, will encompass market power across all these services. In other words, separate market power tests for a different segment of a single unified market are not warranted.

Going back to this idea of time, in certain definitions of market power, significant period of time is replaced by non-transitory. Economics have long held that inferences of high price that would result in temporary or transitory market power-like conditions are not harmful and may even be beneficial for the development of an industry. For example, the current system -- the ability to raise prices above competitive levels for a short period of time is not something we should seek to regulate in my opinion. In fact, we should try to preserve such abilities.

In the context of power market, transitory price increases can represent scarcity rents, which are above margin cost profits that generators garner during periods of tight supply demand. I believe scarcity rents are legitimate because they signal the need for new investment and demand response, allowing existing generators to recoup fix costs that they would not fully capture otherwise. They are transitory because they dissipate as soon as the underlying conditions leading to the shortage are removed or reduced.

Scarcity rents, in my opinion, are in direct contrast to a more long-lived persisting price increase, that is, the hallmark of real durable market power. However, the current set of market power tests do not necessarily differentiate between scarcity rents and market power. In fact, we can imagine the set of conditions where scarcity may be misinterpreted from market power in the interim screens, especially, in the pivotal supplier tests. This would be a classic example of Type 1 error in economics. That is, someone who does not have market power, but nevertheless fails the test. In my opinion, regulating scarcity rents out of this market would be disastrous for investment and long-term sustainability of this industry.

How should we cope with this shortcoming? I suggest a number of possible avenues -- three, in fact, in my written statement. First, and this is by far the simplest and something that I believe some applicants have already done, that we can add context to the pivotal supplier test by also describing the market conditions around the test.

Does the supply demand balance suggest scarcity conditions? At least it could give us an indication of possible errors in the conclusions. An alternative and a preferred approach, in my opinion, is to consider the pivotal supplier test over a multi-year dimension with expected changes in supply and demand. There is an abundance of data on expected demand conditions over the next few years as well supply changes. Thus, data for such an exercise would not be lacking, even in markets without

RTOs or ISOs. More over, a multi-year analysis corresponds to the basic forward-looking premise of market-based rate authorization that the Commission has out and the three-year period of review currently utilized.

A third approach, and one that I will discuss further, and one that Jim discussed very briefly, is the idea of alternative -- actually, all the panelists have discussed this idea of an alternative diagnostic measure for market power, but I will specifically focus on the idea of the use of simulation of computer-based models.

Before I get there, though, we still haven't discussed the second aspect of the classic definition of market power -- the pricing aspect. In my opinion, it's important that a test for market power consider price consequences since market power is an economic activity played out through prices. Neither of the interim generation market power screens currently use price or pricing behavior.

What improvements can be made? Well, one possible modification is to recast the pivotal supply test as a residual demand analysis. I think Jim spoke a little bit about this and I won't go into much detail about what that means. I do discuss it in my written statement and I believe one of the key benefits, and there are actually a number of advantages of the residual demand analysis, but one of the key benefits is direct benefit of market clearing prices. It requires some use of simulation models, but I don't find this to be an onerous task as a practitioner. And I believe there is sufficient data in the public domain to complete such an analysis.

I'd like to speak a little bit now about the other market power test. Section 203 of the Federal Power Act relies on the delivered price test -- another item on today's agenda. The delivered price test, and more generally the HHI computation ratio, is a well-accepted market power test and it has served the Commission very well. However, I do think that the delivered price test would benefit from some refinement, especially, in how it brings in price into its conclusions.

Currently, the delivered price test measures the market concentration of available capacity at or below a specific threshold price. In doing so, the test measures the concentration of what I call infra-marginal capacity. In other words, it looks at the concentration of generation dispatched to meet load at the selected price level, but it does not evaluate the competition for the next increment of demand. Thus, it does not really describe the market concentration of capacity that would be competing for the next increment of demand and that would be price setting in a transmission constrained network.

I do think, though, that the delivered price test could easily be modified or a secondary test created that would look at the market concentration of the capacity competing to serve the megawatt of demand. In fact, it would use the same underlying data base that it was already created to do -- the residual delivered price test. We have the results of that analysis in the context of several markets. In my experience, that analysis has been very worthwhile.

Another possible avenue for market power analysis would involve an adaptation of the well-known hypothetical monopolist or SNNIP test. The SNNIP test has traditionally been used to evaluate the market definition aspect or the boundaries of a market by answering the following question. What is the smallest market area that a hypothetical monopolist can be expected to profitably monopolize?

Using the concept of the SNIP test, we can analyze whether an actual supplier can sustained increased prices over a significant period of time. This goes back to the idea of simulation models and to use computer-based models to help analyze these questions.

There's been substantial research and development of simulation -- game theoretic and empirical models for analyzing market power. In the last few years, and in my experience, the classical model has been moving closer and closer to being able to replicate patterns of actual behavior and price as observed in markets. More over, the level of detail necessary to run those models, in my opinion, is already in the public domain. So modeling can realistically be practiced in ISO and non-ISO areas. Many of these models represent a much more precise and refined picture of the supplier and demand side of the market.

As we know, the HHI analysis for a delivered price test does not really go in as the market share. Thus, the simulation models are more likely to acknowledge the possibility of more subtle and more complex abilities to exercise market power.

In conclusion, there are a number of well-accepted and quantitatively rigorous approaches that can be brought to bear on the issue of market power in the generation sector, both from the perspective of market definition and market power diagnosis. I believe, rather than describing default market definitions, the Commission should recommend guidelines and prescribe analytical techniques for establishing a relevant market definition. Such an approach would be adaptable across time, across market rule changes and across market divide chooses.

On market power testing, the Commission, in my opinion, needs to address some of the well-documented shortcomings of the current tests in light of scarcity and pricing. Even if the interim screens and methodologies for market power analysis are refined and retained, I also believe that the Commission should allow applicants to present the results from simulation models and other market power diagnostic measures for review and as a supplement to the set of tests required by the Commission.

In a closing thought, along the way we must always keep in mind that some mistakes are inevitable. If we need to err, we should err on the side of markets. Excessive intervention may be even more dangerous than too little intervention in the long run.

Thank you for inviting me to participate in our conference. I welcome your questions and look forward to the discussions.

MR. RODGERS: Thank you, Julia. We appreciate your coming today.

Let's next turn to Denise Goulet, Senior Assistant Consumer Advocate with the Pennsylvania Office of the Consumer Advocate. Welcome, Denise.

MR. GOULET: Thank you. Good morning.

The Pennsylvania Office of Consumer Advocate thanks the Commission for this inquiry into the appropriate approaches to be used to assess generation market power. We also thank you for the opportunity to share with you a retail consumer perspective on this very important issue.

Our comments today do reflect solely the views of our office. There are disputes among offices across the nation, as this Commission is very well aware of, and these views are really solely the views of the Pennsylvania office.

Unlike the prior speaker, I would urge that if you are going to err that you should err on the side of protecting the consumer.

The Commission here is seeking comment on the development of guidelines and screens to be used to assess whether individual entities should be granted market-based rate authority. We believe that the review conducted by the Commission before granting market-based rate authority, and also in reassessing the situation in the triennial rate reviews, is a critical task. It raises a serious question regarding whether markets can produce rates that are just and reasonable where there is a known potential for market power.

The Commission is obligated by the Federal Power Act to protect consumers and ensure that the rates that are charged to those consumers are just and reasonable. If the Commission is going to rely upon markets to produce just and reasonable rates, then the Commission must first ensure that those markets are viable, efficient, competitive and free from the potential for the exercise of market power.

We believe that the first key step in the determination of this potential is through the application of appropriate market power screens. We also believe that a second critical aspect is to continue to ensure that RTOs, ISOs and their market monitors are truly independent. That they conduct proactive market monitoring and that they employ appropriate tools to mitigate the market power they find within their borders.

We want to offer comments on five areas that you raised in the notice -- first, the propriety of the current interim screens; second, the appropriate product market; third, the appropriate geographic market; fourth, the application of the rules to new units and lastly, we'll touch briefly on the affiliator's use.

Our first comment relates to the pivotal supplier and market share screens both provide very useful information to this Commission. We would urge you not to stray from these screens. We do believe that these screens alone do not tell the whole story. Like others on this panel before me, we are urging that you undertake some additional revisions to these screens.

We believe that an entity can pass the interim screens and yet still possess the potential to exert market power. We believe that because that entity may very well be able to control a critical section of the supply curve in the market in which they find themselves. I guess you would put us in the category of those who think the screens can produce false positives as opposed to false negatives.

We believe the Commission should modify the interim screens and require applicants for market-based rates to submit a supply curve analysis. That will allow the Commission to discover where the applicant's units fall on the supply curve and also whether the applicant has the incentive to exert market power. In order to undertake such analysis, we believe that you should require the applicant to submit additional information reflecting the type of units they own and the heat rates of those units.

I'd like to turn now to appropriate product markets. The interim screens analyze the potential of applicants to exercise market power in the energy markets. We submit that this analysis is insufficient to detect all instances in which an applicant might be able to exert market power. Therefore, we would urge the Commission to also require information related to the applicant's ability to exert market power in the capacity markets and the ancillary services market. I think an example best illustrates the merits of expanding the list of product markets that are analyzed.

The Commission has determined that PJMs energy markets are sufficiently competitive to warrant market-based rates. We would agree that those markets are some of the more liquid and competitive markets in the nation. However, that does not mean that an applicant may not have the power to exert market power in the ancillary services or capacity markets. For example, the PJM market monitor has consistently found that PJM's capacity markets remain highly concentrated. He's concluded that market power is endemic to the capacity market despite the fact that the energy markets -- he's found those to be competitive.

PJM market monitor has also determined that upon integration of one of the new PJM companies into PJM's markets that that new entity might well have the potential to exert market power in PJM's ancillary services market despite the fact that he found the energy markets competitive. We would again urge the Commission to err on the side of caution and consumers and that these examples warrant revision to the Commission's rules to require market-based rate applicants to submit analyses on their ability and the screen data necessary to determine whether the market's power in ancillary service markets and capacity markets can be exerted as well as in the energy markets.

I'd like to turn very briefly to the geographic market issues. The Commission interim screen focuses on control areas with the appropriate geographic market for purposes of conducting a market power analysis. However, while a control area may be deemed competitive on the whole, the market may, nonetheless, contain constrained areas known as load pockets. We believe that the market power that can be exercised in those load pockets is significant and should be considered as part of the market-based rate application analysis.

The Commission should require all applicants for market-based rates to submit data related to routinely occurring restrains on the transmission system. Market monitors are very useful locations to get that information as well as control area operators.

I'd like to turn now to the exemption for new units. We believe there is absolutely no reason for the Commission to continue to exempt units built on and after July 1, 1996 from market-based rate applications and from market power analyses, especially, where those units are being constructed by entities that already own capacity within the market that's being analyzed.

As discussed above, even if the Commission were to find that a certain energy market is competitive, load pockets can and do exist, leading to the ability of any generation owner to exert market power regardless of the age of the units.

Additionally, capacity markets may remain highly concentrated, again, leading to the ability of the generation owner to exert market power in the capacity market, regardless of the age of the unit. There's no reason to distinguish between an entity's ability to exert market power based on unit age, a factor that really bears no nexus to the potential to exert market power. Other facts such as transmission constraints, load pockets, market share, pivotal supplier and where the unit falls on the supply curve are far better indicators of ability to exert market power than is age of the unit.

Therefore, we would encourage the Commission to eliminate the exempt for new units, particularly, where those units are owned by entities that already own other significant capacity in the market.

I'd like to turn quickly now to the issue of affiliated concerns. We believe that the existence of ITOs and ISOs remains the best means of mitigating the potential for the exercise of market power, especially, where affiliated transactions are involved. However, the existence of the independent grid operator alone is insufficient to extinguish all potential for the exercise of market power.

As discussed above, the potential for the exercise of generation market power remains even in PJM even though PJM is known as one of the more liquid wholesale energy markets in the nation. While we do not advocate limitations on the number of market-based rate grants given to any particular group of affiliates, we do urge the Commission to consider all affiliates in any single applicant's request for market-based rate authority.

As companies expand in size and geographic region through mergers, through acquisitions, or the creation of new generation affiliates, and as RTOs and ISOs grow, to include more companies that may be under the same corporate umbrella, the potential for market power becomes even more pronounced. Failing to consider all affiliates could lead to improper conclusions about an entity's ability to exert market power. Thus, even in RTOs and ISOs, the Commission should require market-based rate applicants to include analyses and screen data for all corporate affiliates that generate or sell energy into the market.

In closing, I just want to repeat quickly that we urge the Commission to first assess the competitiveness of the markets before authorizing market-based rates in any region and to further carefully assess the potential of any applicant to possess market power in all relevant product markets, including energy, capacity and ancillary services; to assess the ability of the applicant to possess market power in all relevant geographic markets, including load pockets; and for all generation that the applicant or its affiliates may own or control.

Additionally, the interim screens must be expanded to include a supply curve analysis. We would also encourage, again, that new units be included in all analyses within the category of entities that must seek authorization for market-based rates and in market power analyses, particularly, those who already own generation in the market or control other generation in the market. We believe that a comprehensive and complete analysis of the potential for an applicant to possess market power, either upon the initial application or at the triennial review, must be undertaken so that the Commission can determine whether allowing market-based rates is proper and in the best interest of consumers. Just and reasonable rates to the consumer is the goal.

We thank you for the opportunity to share our concerns with you. We welcome any questions.

MR. RODGERS: Thank you, Denise.

Let's next turn to our final panelist for this morning, Mark Hegedus, an attorney with the law firm of Spiegal and McDiarmid here today representing APPA and TAPS.

MR. HEGEDUS: Thank you. APPA and TAPS appreciate the opportunity to appear today to address the generation market power prong of the Commission's market-based rate test.

The Commission has come a long way from the hub and spoke days and we support the Commission's efforts to examine market power issues and to develop market power tests that fulfill its statutory obligations.

Recent technical conferences where the Commission has heard a consistent refrain about the subtle, and not so subtle, ways market power can be exercised to justify these efforts. While today's conference focuses on the generation market power prong, the Commission must not look at this prong in isolation. The issue is not simply whether the applicant has generation market power, but whether the sellers and market-based rates will be just and reasonable. All four prongs of the MBR test bear on each other and, of course, on the ultimate question of the lawfulness of the market-based rate. Because of the connections among the four prongs, the Commission's investigation should not be limited to the generation market power prong alone, but, instead, should examine all issues bearing on the market-based rates.

I realize that some sellers have complained to the Commission that the two interim generation market power screens now in place are flawed. APPA and TAPS have our own problems with the screens. But, if you step back and look a the public utilities for whom the Commission ordered Section 206 investigations, one should not be surprised by the list. Rather, it is entirely appropriate for the

Commission to take a closer look to determine whether the market-based rates public utilities charge are just and reasonable. Billions of consumer dollars are at stake. The resources expended examining the lawfulness of these rates pales compared to the potential overpayments consumers must make if these companies can successfully exercise market power.

Last February, APPA and TAPS comments proposed a practical generation market power test with filing requirements calibrated to the market power potential of applicants. The test is designed to yield relevant, probative and substantial evidence that can be used to assess market power while minimizing the potential for false negatives and false positives.

We will resubmit our full proposal as part of our follow-up comments to today's conference. In the time remaining, however, I'd like to address certain aspects of our proposal -- proposed refinement to it and come to the defense of the market share screen.

I'll start with the market share screen. As the Commission has correctly recognized, screens cannot be determinative. When the screens suggest a problem, the Commission needs to take a closer look. We also worry about cases where applicants pass the screen, but, nonetheless, have the ability and the incentive to exercise market power.

For this reason, we support incorporating an analysis of supply curves into the MBR test. We strongly disagree with those who would ditch the market share screen or neutralize it by using what has been called "contestable load" or "truncated market share analysis."

As we understand this approach, one defines the size of the market the amount of wholesale load that is deemed contestable. If a summer's generation capacity amounts to more than the contestable load, the method calls for capping that summer's capacity of the contestable load level in the analysis.

One problem with this analysis is that it ignores the competitive capability provided by the generation fleets of large sellers, especially, ones that operate their own transmission control areas. These fleets make an enormous difference to those firms' ability to compete and influence price. An IPP with a single plant simply is not in the same position to compete, especially, for buyers wanting load-following type services or power backed by reserves.

The contestable load or truncated market share analysis ignores these important differences. Among the sources of support claimed for this approach is a horizonal merger guidelines provision regarding the assignment of equal market shares, which is used in school markets.

We're all familiar with school milk. I imagine we drank a lot of milk when we were growing up. School systems seek bids to supply their milk needs. However, schools also want fresh milk. These requirements mean that dairies bidding for school milk contracts must have the capability to deliver fresh school milk on a regular basis, which should only necessitate access to dairy farms possession of delivery networks and proximity to the school systems served.

Analysis of these markets involve determining which dairies are in a position to serve the school system's needs. The antitrust agencies assign an equal market share to each dairy that has the capability and therefore can bid on and win these contracts.

As should be evident, electricity markets are not school milk markets. Contestable load and truncated market share analysis assumes that competitors are similarly situated with an equal ability to supply the needed product when, in reality, they are not. Indeed, it turns the notion of leveling the playing field on its head, shrinking down the dominant player so it looks like it's a member of the competitive fringe.

One possible meaning for refinement to the Commission's screens would be to examine the capacity that is available to compete in short-term market separately from capacity that can compete in long-term markets. Entry analysis also differs, depending on whether the market of interest is the short-term or the long-term. The competitive analysis should also not assume that transmission availability is existing. But rather it should look to what transmission is available.

In fact, it doesn't appear to me that simultaneous viewpoint capability does this. However, as the Commission has heard from TAPS witness and Kimber last month, the reality of transmission access often differs from it shown to be available on paper.

The Commission's chosen geographic markets must also reflect reality, especially, when constraints prevent competing supplies from reaching the market. The Commission should simply not assume that the control area or an RTO footprint is the relevant market. Even with an RTO region, transmission constraints separate load pockets from the rest of the region. The Commission's orders announcing the interim screens seems to recognize this in making the geographic market definition a rebuttable presumption, although some recent orders, unfortunately, suggest otherwise.

Where market power is found, the Commission must remedy or mitigate it. However, in RTO regions, the Commission has indicate the willingness to conclude without a case-by-case examination that RTO mitigation does the job.

We do not believe these mitigation regimes have been shown to mitigate market power of specific applicants. The Commission is legally obligated to look at the market power in specific cases to determine what mitigation is necessary.

What are effective remedies? We think this question actually deserves its own technical conference, focusing not just no remedies for generation market power, but remedies addressing all prongs of the MBR analysis. Denial of market-based rates must be one remedy as well as imposing obligations on the failing applicant to offer to sell wholesale power at cost-based rates, especially, where wholesale consumers do not have sufficient access to alternative power supplies.

The denial of MBR authority should extend to sales beyond the applicant's control area if constraints transmission isolates buyers from the larger markets. Not only are these trapped customers discriminatorily denied access to the larger market, that market is distorted because demand is artificially suppressed.

Other remedies should focus on structural changes that remove the ability and incentive for exercised market power. Such remedies should be targeted and tailored to address the market power problems identified for the specific applicant. Appropriate remedial conditions on market-based rate authorizations could include reducing the applicant's size in the market through sales of capacity entitlements. The sellers offering load-serving entities and others opportunities to participate in ownership of new generation, expanding transmission capacity available to access alternative suppliers through setting aside transmission capacity for use by trapped customers, clarifying and strengthening network customer rollover rights, making transmission upgrades, adhering to the requirement that transmission owners plan and construct the transmission system to accommodate the network customers needs and encouraging joint ownership and regional planning of the transmission grid.

Once remedies are identified, the Commission should require a compliance process that ensures that the remedies are implemented. And the Commission must also monitor the remedies to ensure that they achieve their desired ends.

Thank you very much. I look forward to your questions.

MR. RODGERS: Thank you very much, Mark -- and all of our panelists for that matter.

Any questions from our staff at the table?

MR. PERL: The question is for Steve Henderson.

First of all, what you call your "DPT style" test when you're reforming the market share screen where you set a benchmark at 120 percent -- the price is up. First you start with your economic capacity and you subtract native load. Aren't you actually dealing with available economic capacity at that point?

MR. HENDERSON: That's right.

MR. PERL: And AEC and EC can be substantially different -- one to another?

MR. HENDERSON: Right. Uncommitted capacity and available capacity -- the word "available" seems to be associated with the 203 delivered price test in the 205 context. For whatever reason, we used total uncommitted capacity, but it's effectively the same thing. You're right.

MR. PERL: I understand you don't want to necessarily stand by 120 percent of benchmark price. My concern is this, if you limit the supply to people 120 percent of benchmark price, you might still have the proverbial "old clunker" who will still run and still be dispatched in the way that they're being dispatched now. You do not include them in the test, but, in reality, they can run on the high end of the supply curve. There might be market power when the test is not picking up any.

MR. HENDERSON: I don't see how -- let's say we have a market like it has 35,000 megawatts of capacity. And, at peak, it's got 30 megawatts of load. But we're dealing here now with a shoulder period. Let's say in the peak period prices might be like a hundred dollars a megawatt hour, but we're in the shoulder peak period and demand is 20,000 megawatts and the capacity that's in the market is 22,000 or something like that.

If you've got 22,000 in the market, but you've got 35,000 total -- is the old clunkers, if there are any old clunkers actually operating in the shoulder peak periods, in this long peak period that's being analyzed, it's probably because they're in some sort of -- they have to be out for some sort of reserve status. They're pinned at their minimums. They're not setting price. I don't think that you lose anything by saying that those things are just not in the market if you withheld those.

MR. PERL: That's a shoulder season. One thing we've learned over the past few years is weird things can happen in shoulder seasons. In 1998, for example, there are weird dispatch instances. You might have dispatch of the uneconomic unit that don't have a screen throughout the year. Granted, in the shoulder season, it still could happen. You also have plants out on maintenance in the fall and winter. I think that could be more of a problem than your screen is picking up.

MR. HENDERSON: I don't know the frequency with which that happens or how big of a problem that is that you would want to try to capture in a basic screen. If you think that's a real problem, you certainly should look into it.

What I suggest to you, though, is, for exceptional situations like that, you shouldn't construct a screen that would bring in all 35,000 megawatts of capacity. Most of the stuff above, let's say, $50 is just not in the market. You need to get rid of that.

MR. PERL: I agree. But we have to make sure that things that can happen are addressed in some form or another.

MR. HENDERSON: You're not going to be able to do that by using an inappropriate screen. What I would say is develop a screen to address the basic way you think the market works. And, if there are those exceptional circumstances, of course, you need to look into it. But, if you're not going to understand them by first saying, well, first, let's develop a screen that has all the capacity in it, even in shoulder period -- but you're not going to understand it. You're not going to understand those exceptions. If you've got that concern, you're not going to make any progress in understanding.

MR. PERL: Thank you.

MR. O'NEILL: I haven't studied your contestable screen in detail, but it seems to me that if we step back for a second and ask the question why are we doing screens? My answer, at least, is to get rid of filings here that shouldn't go through a long, drawn out process of studying the market power when there probably isn't any market power for entities that arguably people are going to contest maybe researching for something we can never find.

But it looks like your analysis says that we want to do a lot more in depth analysis and really isn't a screen where we can press a button and get a number out. Does it make any sense to avoid having a detailed argument for screens over a very large entity that everybody can sort of touch? They think it has at least some kind of market power potential and simply go to a more detailed analysis -- I mean, maybe with enough time so that you don't have to institute a 206. But, just realize the fact that a simple screen is not going to get you anywhere and maybe for large entities maybe we should just stop pretending or looking for that magic elixir.

Let me, while I have floor -- Mark, if we go back to cost-based rates, and we offer the stuff at cost-based rates and more customers show up than we have capacity, what do we do? And, for our simulators in the market, how do we get the demand elasticity right when, in fact, it looks vertical to most of the markets that we deal with today? And, as far as I can tell, that gives you infinite prices under some occasions. Thanks.

MR. JAHN: Let me deal with the first part, Dick. Let's just go to the 100,000 for a moment and look at the regulatory framework of how these screens are tied basically together. To me, the meetings that I've had with the Commission staff it's apparent that there's a definite need for what I would call an administrative sorting screen because you're facing four or five hundred applications a year.

What I need, from my point of view, from a regulatory framework is a need to have a set of indicative screens whose sole purpose is to identify the potential for the applicant to possess market power.

Dick, that has to look -- a whole series of IPPs, EWGs, all the way up the track. Once you've done that, then the big question is, where does the Commission go at that point?

From my perspective, the DPT is just another variant on an indicative screen. I think you've got to jump into an analysis that says what is the actual state of competition in the marketplace? That's a piece of information that can be provided to the Commission by looking at historically what has happened within the market. To me, the two are perfectly together.

MR. O'NEILL: I guess maybe we're just talking about whether we should call it a screen or just call it a detailed functional analysis of the problem, John. Yes.

MS. FRAYER: I'd loved to take the chance to answer the question regarding demand elasticity -- put my two cents in.

I think it actually boils down to, first, answering the question of time dimension of the market. If we believe that the appropriate time dimension for the market is short-term, one-hour interval, I agree. I think nobody can disagree that the demand side of the market basically faces a very elastic or wholly inelastic demand curve because we need to serve that demand if we actually test the hypothesis and decide that the time dimension is much longer possibly.

MR. O'NEILL: How much longer?

MS. FRAYER: That's a good question.

MR. O'NEILL: Important, though. Three years, five years.

MS. FRAYER: One of the keys to being able to do the market power test correctly -- I believe the time dimension for the market, if we step back and look at how do you define the market, when you think about what's the smallest market area where you have substitutes, you include all substitutes within the market.

If you look at that same idea from the

perspective of the time dimension, substitutes really boil down to what are the current commercial range when it's in the industry. What type of substitutes do customers have? Will they come purchase in the spot market real time or can they go out and contract? Right now we don't have substantial customer contract markets.

I'm involved day-to-day. I think you can get quotes maybe for one to three years, maybe five years. If you're looking at PJM, you're comfortable with that liquidity. But you're not going to get substantial quotes 10 years out at this point in this market.

Another aspect of substitution for this market is on the supply side. That, too, is going to really limit the market definition from the time perspective. On the supply side, we're talking about how long does it take for you to get reinvestment in the ground -- actual regeneration, possibly transmission. The shortest amount of time really for new generation is maybe 12, 24 or 36 months, depending on what type of generation you're talking about -- more base-load plants.

In my mind, you put these two pieces together -- demand-side, commercial realities of competition, commercial arrangements -- probably three years, five years. I would say at this point maybe closer to one to three years. And you put together also supply-side substitution on investment and that's probably also around two to three years.

MR. O'NEILL: If we use your three-year rule of thumb, we wouldn't be discussing California.

MS. FRAYER: I think we'd be looking at California differently for sure.

MR. O'NEILL: Well, three years -- the problem didn't last three years.

MS. FRAYER: Maybe, probably some of the drivers to the problem. You talked about underlying shortages. That's what participated. For example, hydro conditions have generally improved substantially.

MR. O'NEILL: Would you have not just sort of chalked up California to a short-term blimp?

MS. FRAYER: I think I would have to take a look. I frankly believe that we should have done the market definition stage very aggressively there in order to determine market power. I'm sure it was never done. For example, if California, a statewide geographical market definition did control most of the state or was, in fact, a geographical market that consist of two markets -- southern and northern California where you may have problems in one and not problems in the other.

You also have to take a look at the product dimension in California so we understand whether or not we're looking solely at what was traded in the spot market or off the contract.

MR. O'NEILL: How do we incorporate this into a quick and dirty screen?

MS. FRAYER: I think that is actually answered with the previous discussion we just had. I don't think there's a quick and dirty screen. I think there needs to be guidelines for market definition. There are quick and dirty analyses that have been practiced now for 5 or 10 years by DOJ and litigation by FTC and other regulators that do look to market definition. Those are quick and dirty, definitely, in terms of actual analysis of market power.

I strongly believe in what you said, Dick. That we need, basically, a cross-benefit approach. You don't want to do an analysis that cost millions for an applicant that clearly has no potential for market power. So we need to ratchet up that market intervention as we go along.

MR. BUSHNELL: Since we're jumping into the simulation questions, I'll jump in, too. I would look at this the same way we're looking at the existing interim screens. You're really thinking about where the elasticity is coming from -- from the competition, from the other firms in the market. So you define the firms of interest and you take everybody else. They are competitive fringe. You look at their supply. If you want to simplify things, you ask that they build their stackup model, fit a line through it, fit a curve through it.

MR. O'NEILL: All the elasticity comes from alternative suppliers, not from the demand side.

MR. BUSHNELL: That's right.

MR. O'NEILL: And, when you're approaching that demand side, what happens?

MR. BUSHNELL: I don't think you need a demand side in there if you're looking at hourly markets.

MR. O'NEILL: Do you disagree with your buddy, Bernstein?

MR. BUSHNELL: Let's put it this way. I would love to see actual demand be elasticity. What I'm saying is don't simulate it in the screen if it's not there. And that's where I'd love to give people credit. I'd give them a lot of credit if they could get demand elasticity in the market in terms of being able to pass this screen.

All I'm saying is, could we run these models without a demand in elasticity? I think, legitimately, there is demand in elasticity provided by the operation of ISOs, by people -- heating and operating reserves below whatever margins they're operating, normal conditions for and that provides interruptible loads. I'm perfectly willing to give credit for those sorts of things -- a fair amount of credit. But, just looking at the other firms in the markets, defining residual demand out of that, I think gets you a long way. It would have captured California. It would have certainly pointed to potential trouble there.

I think the real question would have been, would we, in 1996, have forecast the demand levels in 2000? And I think, under some scenarios, we probably would have. I think the big difference there, again, is that there were no long-term contracts as opposed to looking at some of these other markets where, if we had been in there, the same kind of approach would indicate that there wasn't nearly the same kind of problem in those other markets as there was in California.

MR. O'NEILL: How much time and effort would it take to do one of these analyses?

MR. BUSHNELL: The gauntlet keeps getting thrown back to me to the oligopoly model folks about, well, you know, we run lots of these analyses. That's what I've been playing around with -- how far can you take this? I think, if you wanted to linearize the supply, you take a linear residual demand based on drawing a line through the cost groups of the competitors in the market. You've got a formula you can do on a spreadsheet. I don't see how that's any different than the kind of formula we're talking about in these other screens. Where it gets a little more complicated is when you start introducing capacity constraints.

If you want to model certain key transmission constraints in a market, I think that's worth the effort. But, if simplicity is really the goal, I think there are better simple screens we can do. But it seems like the consensus is that there's plenty of areas where we can avoid simulation.

MR. O'NEILL: Your screen would have us get into the area of cost curve generation.

MR. BUSHNELL: Definitely. I'm hearing that from almost all the panel. It's just sort of a question of exactly how we use that information.

MR. RODGERS: Could I ask a clarifying question in terms of who does these cost curves? Who feeds these models? Is this done by applicants when they come in every three years? Or is this something the Commission staff needs to do on an ongoing basis? And how many people are we talking about that need to feed a model like this?

MR. BUSHNELL: The practitioners here would say, of course, we have the stuff in house. We do at the Energy Institute, too. I think the question is whether you want to establish a data set that is considered consistent across all applicants. Most of the people are buying this from places like Platt's or taking it off the EPA where they're using the data on modern general heat re-estimates and plugging in, basically, industry standard heat rates for stuff that's not in the data. I would bet, if you looked at bunch of different propriety data sets, they're not going to be real different in a lot of dimensions.

I think there's an argument for having a standardized, perhaps, FERC-housed data set on generation costs just so people aren't arguing about some of those aspects in the context of filing. It's not a big burden for most of these applicants to have this sort of stuff provided by the applicant either, though.

MR. RODGERS: How often does this data need to be updated -- daily, weekly, every three years?

MR. BUSHNELL: You want to consider fuel cost variations. I think the rest of the stuff annually is probably adequate. We're not talking about basically going in and major overall in every generation unit's data points. We'll review what major changes have been made.

MR. RODGERS: Is this model, and the data that is fed into the model, is this something that you're recommending that the Commission would undertake and that it would go out and bring people in when it saw market power concerns as a result of the model?

MR. BUSHNELL: I think it depends on the context. If you want to do a really simple screen, you could generate a formula that the applicants could do and it wouldn't be a lot of burden.

If you want to do something that a lot of people have recommended, which is identify subregions using sort of well-recognized transmission constraints to define the regions and then do a regional analysis where you're looking into the all the firms within a region, that's something that you could do. Then I think we're talking about a small enough number of analyses that it wouldn't necessarily be prohibitively onerous on you. But I think allowing the applicants to do that -- if you do an analysis, the applicants are going to come in with their own versions of such things anyway, I would imagine.

And so I think there's real merit in having the Commission house the data and attempt these kinds of analysis. But I don't consider that to be critical to the process.

MR. RODGERS: Okay. If I understood your testimony earlier, you had mentioned that one of the problems or shortcomings that you perceived in the oligopoly models that you've developed or been associated with was trouble measuring the retail obligations of suppliers in the market. Is that correct?

MR. BUSHNELL: No. That was a problem I found with the interim generation screens, which we heard sort of both sides of this argument here. Everybody recognizes that a firm with a bunch of retail load that is providing it cost-based rates is not as big as it might appear if you looked at just its generation. So really the question is, what to do about that, and that's what Kelly's question was getting at.

One way is to sort of truncate the native load off and try to do some version of a concentration measure based on that. That is just a way of trying to deal with this in an ad hoc fashion. I think, looking at the 704 data, looking at the native load obligation makes sense. Again, these are not data that are really hard to come by. I would do something different with it than apply a concentration measure.

And I would add that one thing you need to consider is whether these native load obligations are under rates that are cost-based locally because of local rate base. Or, if they're in some way under a process that is index to wholesale market prices. And this is where the Pennsylvania sort of context would be of concern. You have a retail provider whose retail rates are going to be indexed through wholesale prices. That's a completely different dynamic than if you have retail rates that are basically fixed through a regulatory process at the state level based on average costs. But I think these are not, again, really difficult data to come by. I think every version of the model modifications we've heard today involves some way of assessing that kind of information.

MR. RODGERS: Mark had his card up. Then I'll come back to you, Steve.

MR. HEGEDUS: First of all, I wanted to comment on the models. I actually think it's good to be talking about it and to be exploring it. The concern we have with it is that the details really do matter, particularly, some of our smaller members are going to be the ones who get lost in the details and hurt. So I think the validation process is vitally important to us and that we are sure that the model, in fact, reflects the actual competitive dynamic in the marketplace.

Secondly, I wanted to note that this discussion about how to deal with the native load points to a concern we have with just the blunt chopping off or cutting out of the capacity for native load. What we're hearing is how native load effects incentive and ability varies from company to company, from state to state. And one of the things we tried to do with the tests we proposed last February was provide a vehicle so that you can look specifically at how state regulatory rules affected the intent of the ability when it came to accounting for native load.

The other thing I wanted to address was Dick's question with respect to cost-based rates. We look at that as a specific remedy to a specific market power problem. How you design those really will be dependent upon what you find as a result of your investigation.

In terms of the ability of cost-based rates to attract capital, I think the rec ^\^U('pretty good. Companies that continue to operate under cost-based rates are doing quite well in a steady stream. Certainly, the model of cost-based rates and the ability to give shareholders value is a good record.

MR. O'NEILL: Mark, my question was when the cost-based rate attracts more offers than the capacity of the cost-based rate.

MR. HEGEDUS: Presumably, at that point, someone, including the generator, may want to build some more generation.

MR. O'NEILL: But how do you ration the existing generation?

MR. HEGEDUS: Obviously, that's a difficult question in terms of rationing the generation. What you're suggesting is you don't have a market to sell it to the highest bidder. If I came to that problem -- I guess I'm not convinced that I'm going to come to that problem. But, when I come to it, obviously, I agree with you that that's something we need to think about.

MR. O'NEILL: Let's look at the other side. When the cost-based rate is significantly above the market, and you post the cost-based rate, which is enough to attract capital, and few people show up, what do you do with the stranded costs?

MR. HEGEDUS: That's one reason you need to look at the specific market power problem that you're dealing with. It may be that in that situation that may be the better answer is to increase transmission capacity in order to open up the market to give the trapped customers access to the market.

MR. O'NEILL: But history here at this Commission is every time the Commission has opened the market up it faced stranded costs. In other words, the cost-based rates were significantly in excess of what the market was offering. Should we go through another round of that so we can experience it one more time?

MR. HEGEDUS: Your question presumes that there will have been generations specifically built to deal with this remedy. Then that possibly that will then obligate the Commission to deal with the stranded costs. That was the premise arising out of Order 888 was this idea that pursuant to other kinds of regulatory regimes that operated the construction of that generation.

MR. O'NEILL: And 436 and 636? What's going to change the next time around when we go back to that system?

MR. HEGEDUS: It's not clear to me that we're going back to that kind of system in terms of a proposal that I've put forward.

MR. RODGERS: Cliff, did you have a comment on what Mark was just saying?

MR. FRANKLIN: I had a different question.

MR. RODGERS: Hold that a minute. I wanted to come back to Steve Henderson.

MR. HENDERSON: While it's still fresh in our minds, I wanted to weigh in on our discussion of simulation models.

Of course, as a practitioner, it's hard for me to say anything against simulation models, although my partners on 12th Street are salivating at this discussion. That said, I think simulation models are great. You can do a lot of things with simulation models that get it right in the sense of truncating capacity commitments. If you can put the contract -- the fixed price contract, you can put that into the model and see what the model tells you about the behavior that profit maximizing in those circumstances. All of that is good, theoretically very nice.

I just have two comments and they're negative comments. No. 1, it's not a screen. There's no way that you could employ this as a screening device. Maybe you could use it on an exceptional basis or have Commission staff rewriting these things -- kind of checking on stuff. Maybe that's okay. But the single problem you have got to come up with, it seems to me -- I did simulation models for market power analysis at least on one occasion and found that the object of my affection at the time was able to increase prices by 1 and 1/2 percent and thought that was a great result. It was in the context of trying to promote retail competition in the operative markets and somebody was able to increase prices by 1 and 1/2 percent. That sounded like no market power to me. I got hammered by people who said, 1 and 1/2 percent, that's outrageous. Multiply that times ta-da and you get millions and millions and millions of dollars.

The problem with behavioral models is what's the standard of review? I've asked this to the Federal Trade Commission staff. I've asked it to DOJ staff. You've got a 5 percent price increase threshold that you use for the hypothetical monopolist test and that leads to the structural measures. That's all fine and dandy. But are you willing to import that same standard over to a behavioral model? The answer that came back from both of those staff was, no, we're not willing to do that.

Any price increase epsilon 1/10th of 1 percent is too much and it's the case, particularly -- you might be able to use one of these simulation models and find, on occasion, that somebody small is not able to raise price. That can happen. If it does happen, it is strictly because there are flats in the supply curve and you just happen to be operating within all those flats and nothing changes. If you linearize it and have an upward sloping supply curve, I'll guarantee you every time you exercise one of these models, you'll find that there is at least some small increase in price that is profitable.

You're going to have to say, okay, that's going to happen. Sometimes they're going to see 2 percent and that's bad. Sometimes I'm going to see 1 percent. Maybe that's not so bad. But you're going to have to have a standard of review that says at some point I'm going to let the problem go.

And, if you don't do that, and this is kind of a discussion among staff, but I'll look over to the table over here. This is a set of Commissioners that you're going to have to persuade to adopt a standard where their Federal Trade Commission Commissioners have not been willing to do that and the DOJ has not been willing to do that.

If you could persuade them to take the lead and set antitrust standards on this score, I would cheer for that. But I think that's going to be needed if you go this direction.

MR. RODGERS: Marybeth, I think you had your card up next. Go ahead.

MS. TIGHE: Thanks, Steve.

Me. Hegedus, you mentioned the need to consider transmission constraints, I believe, in defining the relevant geographic markets. And I think others of you have also touched on this. What metrics would you suggest we use in doing that? What standards should we use to indicate that a constraint is significant or not? Are we talking about recurring TORs, extended outages? What metrics would you suggest that we consider in making that determination of a smaller, relative geographic market than the control area?

MR. HEGEDUS: I think that the information that is being asked for as part of the simultaneous import capability study starts to bring in the kinds of things you want to take a look at, but you need to understand what is the total transmission capability. But you also need to understand what is the available transmission capability. It may depend upon what kind of market you are modeling or you are interested in. If it's a spot market, or just short-term transmission is needed, that's going to, perhaps, give you a different answer than if the market of interest is a long-term market when the only thing that will be able to support a generation sale is a firm transmission path.

I am not sure it boils down to a simple metric. It is a question of taking a look at the information that is available to us. I think it's also incumbent upon the Commission to also have the information available to it.

One of the things we have encouraged in our comments is that the Commission has, as part of the obligations on public utilities, to report the transmission data to the Commission so that the Commission can undertake a proper analysis of transmission constraints, including for defining geographic markets appropriately.

MS. GOULET: I would agree. I think reporting is a critical part of it. I think the job is easier in an RTO or an ISO because you do have market monitors who are looking at this information every day. I know the PJM market monitors the way they undertake mitigation procedures. That's exactly the criteria they are using. They're looking at whether there are routinely occurring constraints within particular areas that are creating load pockets.

I don't think they're so concerned about the infrequent situation where a line goes out of service for some bizarre reason. I think, under their rules, they would still mitigate in that situation. But, in terms of what you're looking for -- the actual overall analysis of an entity to see if it has market power -- I think you ought to be looking at where are the routinely, frequently recurring constraints on the system. What you're trying to capture is where is the incentive for someone to exert market power and does this applicant own units within that load pocket, if it exists?

MR. PEDERSON: If I could just ask a clarifying question on this load pocket discussion and the date. One of the things that the April 14th order sets out is that applicants can come in and make these types of arguments. I'm wondering whether the applicants out in the market have the data available to come in and make a showing to the Commission that there is a load pocket. Or is it really incumbent upon the Commission to go out and get that information?

MS. GOULET: I would suggest that an applicant, if they're not a transmission owner, may not have that information. But a control area operator certainly would have that information. And, if it's within the borders of an ISO or an ISO, that market monitor would definitely have that information.

MR. HEGEDUS: I echo Denise's response in terms of a transmission owner applicant who is likely to have information or are more likely to have it than the applicants who are not transmission owners. That's why I think it's important that the Commission have a reporting obligation on the part of transmission owners so that that information is available, both to the Commission and to intervenor and people who need it in order to do the analysis.

Another thing I would note with respect to the simultaneous import capability studies, at least some them so far are being filed are being protected as critical energy infrastructure and, particularly, given about a three-week turnaround time to respond to the applications that have been file or the studies that have been filed so far. It's kind of difficult to get the information practically. And so it raises a question in my mind as to whether everything that's going into the simultaneous import capability study is, in fact, critical energy information infrastructure. I think that's something that needs to be thought about in terms of whether the designation is being done to broadly in keeping information away from people who need it.

MR. RODGERS: I had a couple of questions I wanted to ask Lou about RTO matters and also the contestable load proposal that EEI has.

First of all, I wondering, Lou, if you think the Commission should retain the exemption we established in the April 2004 order for those selling into RTOs and ISOs?

MR. JAHN: The difficulty there is what has always been of concern to EEI is that the apparent discriminatory treatment, if you're an RTO versus if you're not an RTO and a different standard being applied that way. From that perspective, and, particularly, how it loops back to the contestable load analysis, we would view those standards as such that would be applied in assessing whether or not you should get MBR authorization to be standard, both within and outside of an RTO.

MR. RODGERS: I know in several rounds of comments that you all have filed over the two and half years leading up to our April order, on at least two occasions, EEI had said that you supported an RTO exemption. You supported those selling into RTOs should not have to undergo the test and the Commission ultimately decided not to do that. Are you saying EEI has changed its position on that matter?

MR. JAHN: No. I'm just doing it within the context of the contestable load analysis and how we view that being applied.

MR. RODGERS: Whatever the appropriate screen is, if the Commission went with the contestable load or went with some altogether different screen or stayed with the screen we have now, whatever screen we use, is it EEI's view that those in RTOs and ISOs should not be subject to the screen?

MR. JAHN: Yes.

MR. RODGERS: You said earlier, though, that you believed it was appropriate that the Commission would have a market power test of some type. Understood that you don't think of the current version as correct, but, nonetheless, the principle of having a market power screen is appropriate. Correct?

MR. JAHN: The same response I gave to Dick. I think it's appropriate to have an indicative screen for sorting purposes and then a follow-up, more detailed screen to address what's actually happening within the marketplace.

MR. RODGERS: I guess my logical conclusion to what I understand EEI's position is the real focus of the Commission's attention in terms of market power issues for purposes of a generation screen should be in the Southeast and the West because those are the parts of the country that do not have RTOs and ISOs. Is that correct?

MR. JAHN: It's correct that they don't have RTOs in the Southeast. Yes.

(Laughter.)

MR. JAHN: Yes.

MR. RODGERS: Okay. I just wanted to clarify your views on that. And, just to make sure I understood the focus, a market power screen should be in those parts of the country -- the West and the Southeast.

MR. JAHN: No. Well, inherent within an RTO is a market monitoring process, that is, a continuous, ongoing monitoring to determine whether or not there were market power issues there. That is an ongoing process and you're going outside the RTO with another process.

MR. RODGERS: I understand. The screens that we're talking about either staying with or changing here in EEI's view really need to be applied in the Southeast and the West and not in the parts of the country that RTOs and ISOs because those parts of the country have market monitors and other protections in place. Correct?

MR. JAHN: No. Let me back up again. What we're saying here is based upon the April order where the RTO exemption, or I guess the follow-up order where the RTO exemption was removed by the Commission, we would want these tests that we proposed be contestable load, plus modifications to the indicative screens to be done both inside and outside RTOs once the Commission changes its position on whether or not they should be an ongoing RTO exemption going forward.

MR. RODGERS: So then it is your view, or it is the EEI's view, that you've changed positions in terms of whether there should be an exemption for those selling into RTOs because your earlier comments said that there should be an exemption. If I heard you correctly just a minute ago, you are not saying there should not be.

MR. JAHN: No. In the past, the EEI has taken the position that there should be an RTO exemption in support of that in the past. Then the Commission removed that exemption. From our perspective, on an ongoing basis, given the mitigation framework that exists within RTOs, it would be prudent to reinstitute that.

MR. RODGERS: Reinstitute the exemption?

MR. JAHN: Right.

MR. RODGERS: Let me ask a couple of questions, if I could, on the contestable load proposal that you all have. If I understand EEI's position, one of the problems with the Commission's current screen is that it looks at off-peak times of the years to begin with. But, in addition to doing that, it looks at the off-peak season in an inaccurate way, according to EEI, because there's some likelihood that that surplus capacity will exist during off-peak periods. Is that correct?

MR. JAHN: Stating it a little more clearly, our concern with the market share screen is the fact that it is only looking at capacity of the market and it's not looking in different time periods as to the relationship of the demand to the supply within those time periods.

MR. RODGERS: Let me ask my question, I guess, more directly then. Should the Commission be looking at market power issues in non-peak periods, according to EEI?

MR. JAHN: The Commission should be looking at market power issues in all time periods. Correct?

MR. RODGERS: In all time periods? Okay. In terms of how one measures those that are actually seeking competitive supply, under the contestable load approach, one of the recommendations that EEI has, in terms of how one could go about measuring that, is to use RFPs who was soliciting power in an RFP process and just using that process to sort of measure what the demand is out there. Is that correct?

MR. JAHN: Yes.

MR. RODGERS: Do you think, though, that there are, in fact, other sources of demand in the market besides what just shows up in a formal RFP solicitation process?

MR. JAHN: The RFP solicitation process was offered as an example of one type of information you could look at. There are other types of information. For example, since you're talking about a portfolio analysis that would be looking at different segmented wholesale market demands that are in play on a contestable level.

MR. RODGERS: Okay. Is it your view, if I understand it, that the focus of the supply in the market should be that which is available in the control area, not that which is outside the control area under the contestable load approach? Is that correct?

MR. JAHN: No. That's not correct. The

contestable load analysis -- a key part of that looks at supply in adjacent areas that can be imported into the area and is part of the composite competitive resources that a contestable load can access.

MR. RODGERS: Thanks for clarifying that. I misunderstood that. I appreciate that clarification.

This question is actually for you, Lou as well as you, Steve. You have proposed, in your case, Lou, a completely different type of approach to what the Commission currently has -- the contestable load approach. And, Steve, you proposed some pretty significant revisions to that that you feel would improve the Commission's screens.

Have either of you done analyses or test runs to see approximately how many entities would pass or fail these new screens?

MR. JAHN: In terms of the contestable load analysis?

MR. RODGERS: Right. You haven't tried this, so you're not sure.

MR. JAHN: There have been, I believe, about 10 companies of the 36 holding companies that have filed for MBR authorization have included variance on the contestable load analysis, but I have not looked at details.

MR. RODGERS: For those 10 of the 36, did they all pass the contestable load analysis?

MR. JAHN: It depends on how you would define the criteria and it depends upon the nature of how those were structured. I'm just offering that as a comment for you if you want to take a look at it, but we have done no independent study.

MR. RODGERS: As they define the criteria, did they pass the contestable load analysis?

MR. JAHN: Yes, they did.

MR. RODGERS: You mentioned before, in speaking engagements that we've had, that one of the concerns that EEI has with the current screens is that too many IOUs, in particular, seem to be failing the screens. Is there some threshold that the Commission should be looking for in terms of how many entities or what type entities are passing or failing the screen?

MR. JAHN: No, I don't believe so. Once you kind of get into the situation, from my perspective, you should be looking at assessing whether or not the supplier actually does have market power within the control area market. I don't think you should go at this by saying, okay, we need to have 10 percent of the applicants fail the screens and not get MBR authority and then work backwards and develop a screen that gives you the 10 percent number. I don't think that's appropriate.

MR. RODGERS: All right.

Steve, did you want to comment? Have you done any tests or trial runs on who passes or how many entities would pass or fail?

MR. HENDERSON: No. I certainly have done no systematic survey of however many that have failed the tests so far. I have not done that. I haven't done that even for my own set of clients, which is a pretty small subset of that larger group.

MR. RODGERS: Okay.

Jerry, did you have a question?

MR. PEDERSON: I had a question regarding native load and, in particular, the contestable load. We've heard in previous conferences that utilities with large peak generations often have a good portion of those generators that swing between serving retail load and competing in the wholesale market. I'm wondering how the contestable load analysis takes that dynamic of the market into account.

MR. JAHN: One of the things -- in my oral comments, I felt one of the directions that you should be going is to looking at more over an 8760 time span and looking within each hour the actual amount of capacity in that hour that is uncommitted. So, to the extent that generation swings between supporting retail load and is available for wholesale market, that would evidence itself. If you looked at an uncommitted energy concept, that could be integrated into the contestable load analysis.

MR. PEDERSON: If we're looking at just peak and taking the full native load deduction, doesn't that kind of distort the market because at other times those generators are not committed? They're out competing in the wholesale market.

MR. JAHN: That's the point of the contestable load analysis to get away from just using a single point method in terms of assessing whether or not there's capacity available within the market to expanding it more to a much more expansive multi-arrow concept.

MR. PEDERSON: How many hours over the year do we do that contestable load analysis?

MR. JAHN: It could be a function of the data availability and to the extent to which data is available that enables the analysis to be structure for multiple hours.

MR. PEDERSON: You would support doing that on non-peak hours as well?

MR. JAHN: Yes.

MR. PEDERSON: I would have the same question to you, Steve, regarding an end-of-load deduction. If there's a full native load deduction, how does that take into account the dynamic of having a portion of that fleet of generators any portion during that quarter that could be competing in the wholesale market?

MR. HENDERSON: As best I can tell, there's nothing about that dynamic that's not picked up if you do the analysis that I suggest for a non-peak period. The peak period is one where the market clearing price is a hundred and you want to analyze some non-peak period where prices are at 50. A lot of the capacity that was available for the peak is just not economic at that time.

If you calculate that which is economic, you've got to do a little bit above 50 in order to make the analysis meaningful and I suggest going 20 percent. So, from 50 up to 60, pick up everything, which is potentially economic kind of close to the price that's prevailing. Then do the analysis on that. You will know whether the applicant or anybody's generation is economic and it's in the market. You'll know what their commitments are or what their load is. You'll be making the same kind of analysis in a market share kind of context as you would be making if you, in fact, put all this into a simulation model and said the market clearing price is $50.

Let's say the applicant has 10,000 megawatts of capacity that's actually running and he's got 8000 megawatts of load, committed load, committed on a cost basis. If I do the analysis and -- say that he had uncommitted capacity of 2000 megawatts, and I used that in the market share, I'd be using a simulation model. I've put 8000 megawatts of contract into that simulation model, so that's fixed price. And, in the simulation model, if something is withheld, you can't profit from any increase in the market price with the 8000 that's being served at a fixed price. It's only the 2000 that potentially can earn. That's the same analysis that you're making when you do the economic, uncommitted capacity calculation.

MR. PEDERSON: So you would only take out that part of the committed supply that is under a long-term, fixed price contract?

MR. HENDERSON: Yes. That's why it's important to identify native load, retail and wholesale cost-based load. Yes.

MR. PEDERSON: Another question I'm trying to get my hands on is that, if we're looking at a non-RTO market and looking at a control area that has a dominant supplier, in doing the analysis we're going to limit the supplies based on some price, prevailing price in the market and that dominant supplier may be setting that price. Does that not distort our analysis by using that factor on what supplies get in there?

MR. HENDERSON: I don't think so. I've been using price benchmarks that were going to be close by but external to the control area and into Entergy prices probably pretty good. But you can also look at surrounding control areas. If you were doing the market, that next PJM, you could look at PJM prices. If you were doing California, you could look at California prices. Getting the right price benchmark is important. I don't think that's an insurmountable problem and I don't think -- there's a bit of circularity.

The dominance that you referred to I'm not sure what the source of that is. If you're referring to the fact that they dominant their own retail franchise service territory, I'm not sure what relevance that has. But, if they're dominating the wholesale market, then, yes, you need to look at pricing benchmark that are free from that dominance. I would look to something that's nearby.

MR. RODGERS: Let me next call on Rob Gramlich today impersonating Michael Bardee of the Office of General Counsel.

MR. GRAMLICH: I do have one question on the contestable load analysis. At this point, Mark's milk carton is looking pretty attractive.

(Laughter.)

MR. GRAMLICH: I'm thinking about, if you use that concept, if you're wondering how much milk supply could enter the D.C. milk demand market, you might look around and look up as far as, say, Pennsylvania. And say, well, you know, there are some dairy farms up there that could reasonably serve the D.C. market once you add up all of that supply. Compared to how much demand you have in D.C., you might find, well, you've got three times more supply than you've got demand and it seems like a critical piece of the contestable load analysis was to make that comparison to see whether, in fact, you have access supply, which then indicates low market power. Well, that's not very satisfying of the Pennsylvanians, Philadelphians and people from Pittsburgh who want that milk as well. You don't really have three times as much milk as you have demand.

What do you do in your contestable load analysis? In your response to Steve's question, you said you do take into account the imports that can come in. So it sounds like you're including internal supply and external supply and comparing that to only internal demand. Are you essentially guaranteeing that you find excess supply?

MR. JAHN: No. Because, if you back up, that's the same premise that's in the pivotal supplier analysis. The pivotal supplier analysis looks at the uncommitted demand within the control area and analyzes the total uncommitted supply as a composite of the uncommitted supply within the control area, plus what can be imported, I believe, in from the first tier markets. We're applying that same concept here.

MR. GRAMLICH: That's not an issue in the wholesale market share analysis.

MR. JAHN: The market share analysis uses the simultaneous import capabilities also to define total market capacity.

MR. GRAMLICH: Steve, did you have something to add to that?

MR. HENDERSON: You asked a good question. There's a kind of theoretical problem when analyzing markets. Let's say you've got some excess capacity in some place like TVA and you do an analysis of the Dominion market, the Southern Company market, the Entergy market, the Ameren market, the AEP market -- every one of those, the excess supply that's in the TVA market is thought to discipline the AEP market, the Ameren market, the Southern Company market, Dominion, Duke -- all of them, all the surrounding markets.

How big of a mistake are we making when we analyze things that way? Well, I don't have the answer for you. It's a pretty deep question. But I would suggest to you that a lot of the competition that we're talking about here from this excess supply in TVA is potential competition. It's the threat of competition. The threat can be used multiple times. The actuality can only be used once. So, as long as this is a single supplier -- I'm sorry

-- yes, a single market analysis and we're looking at unilateral exercises of market power, I think we're okay.

If Duke, Southern Company, Ameren and AEP all somehow simultaneously became a problem, then clearly the excess capacity in TVA couldn't be used to discipline all those.

MR. RODGERS: I have several of the panelists who have been very patient with their temp cards up for some time now. In fact, I thought I saw one of them a minute ago folding his into a paper plane ready to fly it up here.

(Laughter.)

MR. RODGERS: And another panelist I thought I saw wrapping his around a rock that he was getting ready to hurl this way. But I appreciate your patience. I think Mr. Bushnell had his card up first, so I will call on him.

MR. BUSHNELL: I just wanted to follow-up on Steve Henderson's point about the oligopoly models producing this uncomfortable amount of information. It certainly is true that what comes out of an oligopoly model will be some estimate of how far places might go above perfectly competitive levels. If you want to define it that way, I think it's important to recognize that any standard one applies through any of these measure implicitly does the same thing, though.

The concentration measures the HHI is based upon is a very simple oligopoly model. When you start determining what an elasticity is, any threshold you're defining in terms of concentration indirectly is determining an acceptable level of markups. I think it's right that you're going to get some market power a lot of the time and it's wrong to say that any amount of market power is justification for denying market-based rates.

But the Commission market-based rate authority is not antitrust policy, first of all. This is something, for better or worse, that defines a tougher standard than antitrust laws and the Commission has had to deal with this in a lot of contexts already.

In the markets I deal with, there are thresholds for impact tests for bidding. There are price caps, absolute price caps. And if you get it too far wrong, there are refund hearings that are also all having to rely upon some way of defining what an acceptable amount of market power might be. So I think it is an issue you have to grapple with. But it's important to recognize that it is one that's there and really can't be avoided under the sort of mission that market-based rate authority provides.

MR. RODGERS: Julia, did you have a comment?

MS. FRAYER: I did want to just add one quick comment on continuation of what Jim was suggesting.

In this idea of figuring out a bright line standard of review is effectively not only endemic to all tests we do, but also needs to be considered going back to sort of what I keep trying to hammer out today, going back to the market definitions. So it needs to be taken in that context. In other words, perhaps, a 1 percent increased that was found to be sustainable may not be sustainable over a non-transitory period of time. That actually brings us back to this idea of the set of prongs that also involve looking at potential intervention. It's time and it's sufficiency and it's likelihood within that set. When we think about the tests and design thresholds, we need to consider that both the tests and those thresholds are designed, vis-a-vis, the key dimensions that we define for the market.

With that, I also wanted to talk a little bit briefly about the question I was just asked about -- milk consumption and the fact that you may have an access supply that's being attributed to a bunch of other -- many people simultaneously. It actually goes back again to the fundamental issue of geographical market design. It may, in fact, be true -- I'm sorry, geographical definition. It may, in fact, be true that, though, right now, based on the default market definitions we used for the current test where we always look at control areas, plus the first tier markets, it may, in fact, be true that certain first tier markets for certain control areas are not really part of the geographical dimension for the market.

This takes me back to something that I wanted to add to the answers that, Marybeth, you got from my fellow panelists on geographical market definition. What's standard? Some of the standards you have suggested are actual occurrence of transmission congestion. In the economic sense, they fall under what I call product flow analysis, looking at physical trade between regions as a way to define geographical market boundaries.

There are also other types of -- and they kind of fall into two categories -- other types of techniques that we can use to look at geographical definitions. There are a lot technical techniques. For example, price correlation analysis, range of price causality analysis, co-integration using the SSNIP's test, the hypothetical monopolist test. It could actually be used very easily and we have actually simulated that to define geographical market dimensions. There is also practical measures.

I think that goes back to what you suggested regarding product flow. We have to take a look and see is it true that a trader has the ability to take power from TVA and get it down to the southwest corner of the FERC-control area. Is it true that a trader in TVA can take it up into the Chicago area when their looking at the market areas from applicants in those market definitions?

There is a lot of precedence is antitrust and dominant cases and various litigated matters for that type of practical indices to be used to actually define the market. So I think, if we build upon that, we may be able to avoid some of the other pitfalls that we face in trying to design the test. So, if we start with the market definition, it might help clear up a lot of the other issues we face attributing load, attributing transmission capacity, et cetera.

MR. GRAMLICH: To do a real quick SSNIP, is that significant and non-transitory increase in price?

MS. FRAYER: Yes. Got an A.

(Laughter.)

MR. RODGERS: Mark, you had a comment.

MR. HEGEDUS: Thank you very much, Steve.

A few comments in reaction to things that have been said. First of all, with respect to Jerry's question regarding contestable load and its ability to take a kind of what I would call the "fleet effect" in terms of what I have seen I haven't seen it being able to take account of that fleet effect. That was the importance of the analogy to sort of the milk markets. What you have in those situations, and where you have competitors who have been found to be equally capable of winning a contract and then you're comfortable with saying, okay, assign them equal market shares -- what we have in electricity markets is often that competitors aren't necessarily in the same position to be able to serve a particular kind of load or a particular kind of management. That was one of our concerns that contestable load wasn't capturing that kind of effect.

Secondly, I want to note that I'm not sure the Commission has to reinvent the wheel in terms of an analytical tool. I think the deliberate price test, in fact, provides the Commission with a lot of what people on the panel here today have been asking for. For example, it implicitly reflects price levels in terms of you run the tests for different periods -- peak, non-peak, shoulder peak. It also reflects the costs of generation because you use the economic measures. So you have tools already at your disposal that we do use that address concerns that you're hearing today.

In terms of other tools, I wanted to note that the supply curve analysis that some of us have talked for also addresses interest in sort of looking at who can supply the next increment to supply. You look at the curve and you can see where particular units on the curve, who owns the units, whether you're in a flat area, a part of the curve, or in the steep part of the curve. What is the concentration? How many people? Who's competing in that part of the curve? That provides useful information in terms of understanding your market.

And the last point I'll make -- and I do appreciate the opportunity to comment. Jim draws an important distinction about the Commission here is not implementing antitrust policy or antitrust enforcement like the antitrust agencies. And I think where that's reflected is in the definition of market power that the antitrust agencies use in terms of having this idea of sustained market power, along with things that they're trying to do is decide when they're going to exercise their enforcement tools with relatively limited enforcement capability in terms of their resources.

And, yes, you have to make decisions in terms of when it's right to intervene. But your standards that you're applying is not a standard in terms of abuse of monopoly power such as under the Sherman Act. Your standard is just and reasonable rates.

I would submit that that imposes a higher standard, a more high obligation on the Commission to look for market power and, perhaps, to not tolerate as much market power as might be tolerated under the Sherman Act. Thank you.

MR. RODGERS: Thank you, Mark.

David, did you have a question?

MR. HUNGER: A question for Steve -- a couple of questions about native load.

I'm wondering, if the Commission went that far and netted out all the native load, would a 20 percent market share screen be the appropriate number? We've heard arguments that 20 percent is too low in identifying, especially, and maybe not in an initial screen, but maybe in subsequent rounds. If the Commission got the native load right, in your opinion, would a 20 percent screen be a reasonable screen?

MR. HENDERSON: I wouldn't change the role of the 20 percent just because we're getting a better measure of native load. I think you can think of the 20 percent, more or less, the way that you think of it now. It's a conservative screen. If you pass it, I think that probably it does mean that the applicant passes subject to what other special investigation might be going on. If there are none of those, I think the applicant passes. But I'd think I'd probably use it in the ultimate decision in the same way that the Commission always has. You look at people who have 28 percent market share and look at it more carefully and decide, for whatever reason, that that's okay.

The antitrust authorities go up to like 35 percent. That range between 20 and 35 percent right now is taken under advisement and I suggest that you just continue to do that.

MR. HUNGER: In Mark's comments, there's a lot on page 7. I'll read to you. It says, talking about the native load, "For example, capacity that, at times, serves native load, but, at other times is available to bid in the spot market, should be counted when assessing short-term markets." That reasoning is consistent with the Commission's practice now of looking at the lowest native load period during the season, assuming that everything else -- at some point you can deduct that much capacity, but at some point during the season that capacity is conceivably competing in wholesale markets. I'm wondering what you think is wrong with that argument.

MR. HENDERSON: I think what's wrong with it is that, when we do these analyses, we're taking snapshots. And, if you take a snapshot of spring and say I'm going to do this partial credit for native load and I'm only going to look at taking credit for like 60 percent of the native load because sometime during the spring you're going to be using that economic capacity.

Whatever that argument is, my reaction to that is, okay, if you think that's true, take another snapshot in the spring. Take as many snapshots as you need. But, for each snapshot, you need to actually be looking at the market. Don't take a distorted view of one snapshot because at some other time something else is happening.

God forbid, if you did 8760 snapshots, you'd learn everything presumably that you wanted to know. But I wouldn't say you get partial credit for native load on the grounds that at some other time in the same season circumstances are different.

MR. HUNGER: Your argument for consistency in a sense. If you going to look at the lowest native load level, look at it for both. If you're going to look at the middle, pick the middle. If you're going with the highest, pick the highest.

MR. HENDERSON: Even though I don't think it's practical to use the simulation model, that's what you would be doing if you did a simulation model. You'd have how many hours you've simulated. You'd have the contracts in for that hours. You'd have what the economic clearing price is, making market shares. You'd be taking a whole series of snapshots, but you don't just restore one snapshot because of some other time period.

MR. HUNGER: That was a very precise definition of native load. Native load would have to be locked up in a cost-based deal.

MR. HENDERSON: Yes. I would point out that there is some challenge to getting that native load calculation correct. One of the things that we're encountering as practitioners is we're learning more and more about load as we go along. We knew a lot about capacity, but we don't know everything that we need to know about load. I'm taking that into account. We need to get the story straight. We need to get an accurate measure of native load. If we don't have it, let's develop it.

MR. HUNGER: Do you think that the measure that the Commission uses for available economic capacity is accurate or close to accurate for native load?

MR. HENDERSON: I think it's pretty accurate. It still suffers to the extent that we take this 714 control area load data and use that directly. In a delivered price test part of that could be non-native load. Separating that out probably needs to be done just for the delivered price test, also.

MR. HUNGER: The reason I'm really harping on it these studies seem to really swing on the native load. If you don't account for native load, a certain class of applicants will almost all fail. If you do account for all of it, then you get almost all of them passing these things. It seems to me, if the Commission is going to work with the screens it has, it seems to be a critical parameter, if you will.

MR. HENDERSON: I agree. I think it's the single most important thing that you need to sort out. The other one that's close behind, though, is, if you really want to look at the non-peak periods, that's something that's come up now within the last year or so. It didn't use to do that. Now it's become plain to me, after looking at a few of these analyses, which you do as you look at the economic capacity in those non-peak periods, and there is some judgment involved in that.

MR. RODGERS: If I could follow-up on what you were just talking about as well as something Julia mentioned earlier.

Julia had mentioned that she did not think -- if I understood her correctly, did not recommend a type of quick and dirty analysis for testing market power. And, for initial market-based rate applicants here at the Commission, we have to get an order out within 60 days. So we are under a clock on those kind of filings and I think that compels some kind of quick and dirty analysis. That's my opinion.

But, that said, Steve, the type of further review or analysis that you were suggesting for certain times of the year where you don't just look at the minimum peak day of a period, but you look at several other snapshots during that seasons, that would seem to me to add a lot more complexity and work for an initial screening process that the Commission, to this point, has intended just to weed out the applicants that need a closer look.

I'm wondering, if we were to take you up on your offer and direct applicants to take multiple snapshots within each season, depending on what the native load was on certain days, would we not, perhaps, get a lot of negative feedback that we were overly burdening applicants with a lot more work?

MR. HENDERSON: Yes, you would. And that's not my suggestion. My suggestion was right now you're looking at four seasons. In the peak time of each of those four seasons -- the reason why my suggestion is simpler than a delivered price test -- the delivered price test has more periods. It has 12 periods. This would have only four. You look specifically at those times. You can go right to the 714 data and find exactly what the load is at those times and provide that between native load and non-native load.

I can get a stacking model and just do that for four periods. That's all I'm suggesting that you do for the screening analysis. I was just reacting to, gosh, if you do that, you know, giving full credit for the native load, there are going to be times during that same season when there's more capacity than that available to the market.

My reaction to that is yes. And, if those additional times are things you think you need to study, fine. Take additional snapshots, but don't distort the spring peak snapshot because there's something else going on in the spring time period, which is even less on peak.

MR. RODGERS: Isn't it true, though, that at some point, and maybe on multiple days, but at least on one day of that 90-day spring season, all of the unused generation that was not devoted to native load on that day is, in fact, available to make off system wholesale sales?

MR. HENDERSON: Could be. Much of it may not be in the market when it's available. That is, you know, the peak spring day the price is 50. On some of those other days, the price is 35. And that capacity between 35 and 50 is not in the market.

If the prevailing price is 35, you cannot increase the price by withholding a unit which goes at $40. You just can't do that.

MR. RODGERS: I know you're here today representing Entergy, but I assume -- well, I won't assume anything. But, let me ask if you think it is more likely that the generation that is competitive in the markets during off-peak is that of an IOU or that of an IPP or can you generalize?

MR. HENDERSON: I don't think you can generalize that -- not readily. A lot of the IPP capacity is pretty efficient gas generation, so that's going to be competitive at certain times. If coal is on the margin, even that's not going to be competitive. But there's going to be -- that efficient gas generation is going to be competitive a fair portion of the time. The old gas-fired steam units are not going to be as competitive.

MR. RODGERS: Cliff, you had a question?

MR. FRANKLIN: I actually have a couple of questions. Hopefully, they're not too long, just a comment.

The historical contestable load analysis idealistically sounds very advantageous doing a market power study. My concern is accessibility of data and definitions. When we developed the simultaneous import capability screen, the Commission staff felt like, rightly or wrongly, that all the data would be readily available like Oasis from network reservations, demand, load flow models. That all that would be accessible to intervenors, applicants and the Commission staff. What we found out is that there has been a lot of feedback that this is tough data to get. So, when you start talking about RFPs, it sends a red flag -- and definitions enter into it as well.

First of all, how readily available is RFP information to intervenors, to applicants, to us? I'm sure we could get it if we requested it. Maybe it's even on file here. I've only been at the Commission for two years, but my question is, how readily is this so-called demand that wanted to participate in the wholesale market? How easy is that to get? I can see some nightmares getting that kind of data. Maybe I'm wrong.

The other question is, what's your definition of demand that's available to the wholesale market. And I can give you an example of, say, the prices got really high and somebody was actually exercising market power. The RFPs might go down. And, if you actually did an analysis in that time period, it would benefit the person who is actually exercising market power because the wholesale demand might weigh down during that hour because price has gotten way out of line and they just decide to run the peakers.

So is it all industrial load or all industrial load with the capability to participate in the wholesale market potentially? Or is it the ones who actually did, which is more or less a function of the market price at that time? I'm just worried about the practical side of this. How do we get the data? How do we define what's native load versus what is -- is it the available load to the wholesale market? Or is it the ones who actually participate? And how would we get the data? That's the biggest question.

MR. JAHN: Let me take a shot at that. I've been at EEI about a year now. Prior to that, I spent six years in deregulated power marketing at both the retail and wholesale levels. And, in the markets I worked in California, the Midwest and the Mid-Atlantic region. It was very easy for us to obtain RFP data. I could tell you RFPs have been issued for a two-year period prior to going backwards. And the markets that I have participated in, off the top of my head, it was very easily accessible data.

Beyond that, there's also very easily accessible data that deals with -- if you wanted to look at what we were talking about, industrial customers that may be into the market, that type of information -- they are also very, very active in the RFP market. That data is available from them.

In terms of the sequence of this, I think it would incumbent upon an applicant that is filing a contestable load analysis to demonstrate the nature of the contestable load data source that was in there. And we have a right at that point to basically challenge that. But, for most of the deregulated markets I've participated in, this information is readily available. There is really no difficulty in getting it. As a matter of fact, there are even subsets of firms out there that actually provide that data to you on a market intelligence basis.

MR. FRANKLIN: It's not considered commercially sensitive?

MR. JAHN: No, not at all. In point of fact, there was a tremendous euphoria, if you want to call it, or expectation on the part of deregulated wholesale and industrial customers that they went of their way to get the information out there such that they could touch base with alternative suppliers. So there was very little of a propriety nature that I've ever find in power marketing where a customer was holding back and he didn't want the market to know what his needs were. It was 180 degrees opposite.

MR. FRANKLIN: Is it EEI's position that the contestable load would be the amount of industrial load available or could participate in a wholesale market or the amount that did actually participate with an RFP?

MR. JAHN: I think that, if you're looking at RFPs, you would be looking at just the RFPs that were issued by the industrial customers. Then I think you go beyond that into whether or not you felt it was necessary in that piece to include customers that choose not to shop that had that opportunity. And that ties back to the whole polar issue, which is another side of this.

MR. FRANKLIN: Just one other quick comment, and then anybody can answer or respond to this.

I've got about a 20-year background in modeling electric markets. I've also got five-years experiences as a state representative. I was in many debates as a state representative that got very emotional. But the most emotional arguments I've ever witnessed and been a part of were modeling between mathematicians, engineers, and analysts. Those were the most emotional arguments I've ever seen and a lot of those dealt with the future.

In regard to simulation, I can see how simulation might be practical if it was done on a historical basis. But, once you get into the future, then oil prices, gas prices, load, GNP -- these all become critical. The stochastic people have their view. The simulation people have their view. There is not any simulation that does a future that won't be open to tremendous scrutiny. And now people have their own way of doing things. Some like to simulate. Some like to stochastically trend to the past. But it would be very hard to get one model that's well accepted by all. That would bring up, in my mind, maybe I'm wrong, a lot of controversy to do anything in regard to the future.

MS. FRAYER: I'd like to just briefly address that. I actually agree with you.

I think it would be unrealistic of us to expect the Commission to say we're going to just use a commercial model and this is going to be the platform.

I do want to correct, Steve, what you said. I don't disagree with the need for initial screens because I think there's a whole set of cost benefit analysis you could do for regulatory policies where there are low probability events in terms of market power. That should carry with them low costs, low regulation. So you need those screens to weed out, as you say, those applicants that don't have any potential in the timeframe.

My suggestion for simulation modeling and the use of models for market power diagnosis is in the second stage when you realize that there is a possible problem and you're not 100 percent confident because we can't be 100 confident in the screenings we use. Then we need to go one step further and take a look at various, more detailed analyses.

I think the way to deal with simulation models is, perhaps, to not espouse a signal model or a single technical approach. For example, don't espouse potentially, well, the Commission is just going to allow supply function, equilibrium simulation models or just this type of model the last applicants to present and intervenors to present. I think the more models that you have that point to the same conclusion under a variety of different possible future conditions the more robust your conclusion will be. So I think the idea is to allow for multiple tests that allow you to confirm the same conclusion or confirm rejection or acceptance of a particular hypothesis.

I do think it does involve a lot of effort. I don't think it's simple and I wouldn't want to convince you that it's the push of a button because these are quite complex analyses. But I think, in terms of data, you do have a lot of data that you've already collected for the initial screens and actually applicants haven't had. You can't tell me that a supplier doesn't have cross-data or hasn't looked at simulation modeling in many instances. I don't think it's a huge burden on them in terms of actually getting set up to do this. It is a burden on them, actually, that exhaust a large likelihood of possible future outcomes and considers alternative sensitivities and alternative formulations in terms of assumptions.

I think that when there's a critical issue at stake, though, an applicant that has at risk 20 or 30,000 megawatts of a capacity not being able to sell at market-based rates would want to go through that process. It's fair for the Commission to be able to allow it to go through that process and have intervenors address shortcomings in their own analysis.

MR. FRANKLIN: Just one really quick question. Those analyses would be fairly complicated and would take time and those things aren't done overnight. Correct?

MS. FRAYER: I don't believe they're done overnight, but I don't think they would take years. There's a timeframe. I do think it would take longer. And I agree. I think that, for the things you have a timeframe where you have to get an answer -- 30-, 60-, 90-day timeframes, that's where the screens are useful. But when deficiencies are noted with initial screens, these are very important business decisions you're making on behalf of companies. I think it's only fair that they have the opportunity then to present all the possible evidence that you can then rule on.

MR. RODGERS: Dick, you've been waiting for while. Do you have some questions?

MR. O'NEILL: Yes. I'd like to move into maybe a more qualitative and potentially jump the gun for tomorrow. I read in today's trade press that there's been yet another settlement on unfair advantage to marketing affiliates. I noticed we've had some of those on our agency here at the Commission recently.

A screen implicitly assumes that all competitors are treated equally. If there is a historical finding of favoring of affiliates or favoring of the owned generators, do these screens mean very much?

Anybody can answer that question.

MR. HENDERSON: I'll not be too timid here. You know as well as I do, Dick, what the screens mean. You could have the potential for affiliate abuse. I think of the screens as independent of the affiliate issue and assessment and it's just a look at the wholesale market conditions, treating all competitors equally. That's as much information as you could hope to get out of it. That's why you have separate affiliate standards and that's why you have the other three prongs.

But I don't think the fact that you find something among the other prongs in any way detracts from the screen because that's not what it was designed for to begin with.

MR. O'NEILL: Could they fail the affiliate prong and pass the screen?

MR. HENDERSON: I suppose.

MR. O'NEILL: And still pass and get market-based rates?

MR. HENDERSON: That's really up to you all to decide. It could be an affiliate problem. That is, you know, that doesn't really impact the participation in the market. You might decide -- it's awfully hard to generalize.

MR. RODGERS: Commissioner Kelliher, did you have some questions?

COMMISSIONER KELLIHER: I had a couple of questions that I think lend themselves to short answers, but I'll leave it to the panelists.

The first one is for Lou. I just wanted to know is a contestable load analysis based solely on historical data or is it the projection on what the future contestable load would be?

MR. JAHN: A very short, quick answer. From my perspective, yes. It would be based on historical because that was the requirement the Commission established I think in the April order.

To me, it would be much more valuable to do it prospectively, also -- to provide an analysis looking out into the future, which would alleviate a lot of the problems that you try and address in the RM04-14 proceeding.

COMMISSIONER KELLIHER: How could you get the information with respect to future contestable load? How readily do people indicate their future sales?

MR. JAHN: What you try to capture is major asset changes and perceived market changes, knowing that would be occurring. For example, if there were known generation increments coming on line within that relevant market, that's what I mean about capturing.

COMMISSIONER KELLIHER: From the purchaser's point of view, how would he know how much load would be seeking a buyer three years down the road?

MR. JAHN: Going forward, you would not know that there. There would just be what I would call peripheral market conditions going on that could impact the tests.

COMMISSIONER KELLIHER: You know, our look has to be prospective in the ability of the seller to exercise market power going forward through the years.

Another question about remedies. The Commission's merger policy statement has a non-exclusive list of remedies that people are invited to propose if they trip some of the screens -- the concentration screens. The April order proposed one form of mitigation, but invited applicants to propose their own forms of litigation. Should the final rules with some non-exclusive remedies -- this might be more for Mr. Hegedus since you discussed remedies. But should the final rule have a non-exclusive list of remedies under the remedies in the merger policy statements we have used in market-based rate cases. The transmission upgrade was used in OG&E. And the limitation on constraint paths was used in Public Service Company of New Mexico in their current authorization. Should there be a list in the rulemaking?

MR. HEGEDUS: I think there should be. But I agree with you that it should be non-exclusive. I think one reason for it to be non-exclusive is that so the remedy can be crafted to the particular market power problem that you identified. And it may be that the list you have in the final rule would not have anticipated the particular market power problem. So I think it's good to have flexibility so that you can be specific and target it.

COMMISSIONER KELLIHER: One other question.

The Commission has a rulemaking on changes of status. And, if you assume we get an exact, precise, perfect reporting requirement on what should be reported for changes in status, should the authorization for market-based sales be longer than three years? If changes in status are reported, why shouldn't the authorization be longer than three years? The Commission has indicated that there's a couple hundred filings that come in and we're trying to balance administrative ease versus precision in decisions. And it just seems that a change in status might make it at least possible to have a longer authorization period. I was just curious what the response would be.

MR. HEGEDUS: I have a response that I'm not sure if it leads to the conclusion that it should be longer. My concern is that the markets are dynamic even though the particular applicant may not have had or may have reported those changes of status, there may be other things going on in the marketplace that have changed the competitive position of that applicant, including to give the applicant market power.

Now the applicant might say, well, it's not my fault. Well, we're not looking for the guilty here. The question is, do they have market power? And, if they do, the standard has been that it's not permissible to let them have market-based rates unless they've mitigated that market power. So I would recommend against extending the authorization period.

COMMISSIONER KELLIHER: Any other comments?

MS. FRAYER: I think I would probably, in principal, concur, Commissioner, with what Mark had said. I would also add to that that question is highly contingent on exactly what they have to report. For example, do they report, yes, they've changed status? Do they go through and do all the analysis every time there's a change of status? At what level, for example, do they need to report when they acquire certain facilities of greater than X size. Or when their contracts expired, which they may have subsumed into their market power analysis.

Frankly, if the reporting standards are all-encompassing so they move the applicant to continuously update the market power analysis, I do think the timeframe may be extended. But, if the reporting standards are more discreet in terms at what level reporting is done and what type of analysis needs to accompany the report. I do think that there's a need for some sort of multi-year review framework.

COMMISSIONER KELLIHER: I had one last question for Mr. Hegedus.

In your comments, you said on page 8 "in RTO regions the Commission had indicated a willingness to conclude without any case-by-case examination that RTO market mitigation suffices to address the generation market power of MBR applicants." I point out that that's not what we have done. We have had case-by-case examinations of applicants for MBR authorization. And I was just curious what the basis of your statement is.

MR. HEGEDUS: There's actually a specific case where the mitigation measures in the RTO region were said to resolve the market power concerns. But, without any kind of linkage of what was the specific market power of the applicant and how was it that the mitigation measures, in fact, addressed that applicant's market power. There was no analysis of that.

COMMISSIONER KELLIHER: Thank you very much. Did you want to comment?

MS. GOULET: I did want to weigh in on that.

I also think that where you have particular mitigation measures that are subject to mitigation -- we're all familiar with the Edison Mission appeal that just got remanded back to this Commission. In that situation, just because market monitors have certain mitigation measures in place doesn't necessarily mean that those will withstand appeal and that that is a complete, foolproof protection for consumers.

I think at the outset you do need to look at, even within RTOs whether there is potential to exercise market power. Then look at whether the existing mitigation measures that the RTO has in place are sufficient to take care of that particular situation.

COMMISSIONER KELLIHER: I think that's what we do. That's why we made the change in the SMA order. But thank you for your answers.

MR. RODGERS: Commissioner Kelly?

COMMISSIONER KELLY: Mark, on page 8 of your testimony, you refer to some recent Commission orders. And you say "recent applications of the interim screen unfortunately suggests otherwise." Could you tell me which ones you were referring to there?

MR. HEGEDUS: Can I do that without violating ex parte rules? Okay.

In particular, the Alliant Companies order assumed that MISO was the relevant geographic market in spite of very arguably strong evidence of a load pocket within MISO that should have at least rebutted the presumption and put this into an investigation to look at it more closely.

MR. KEMP: Was NPPA or TAPS a party in that case?

MR. HEGEDUS: The organizations themselves, specifically, no.

MR. KEMP: Thanks.

MR. RODGERS: I'm going to call on Jim Bushnell and then Debbie. Then we're going to go to the open microphone sessions.

Jim?

MR. BUSHNELL: I just wanted to belatedly respond to the complicated model point that Cliff Franklin made.

I just want it to be clear that, although I agree with what Julie said that it makes sense to do the follow-up analyses in the case of failure, these do not have to be extremely complicate simulation models, depending on how many simplifying assumptions you want to make, which are all less extreme, I think, than some of the underlying assumptions to the screens in the interim order. These are just formulas you would apply. So I'll give an example of this in my written comments. But I think that to say that an oligopoly model is necessarily more computationally intense than something else is not necessarily true.

MR. RODGERS: Thank you, Jim.

Debbie?

MS. LEAHY: There was a question teed up that nobody has addressed. I was just curious. The question of whether the Commission should limit the number of market-based rate authorizations for each corporate family. I was just curious if any of the panelists had any opinions on that?

MS. GOULET: We did address it. And we said that we didn't think it should be limited for the corporate family. But those affiliate relationships need to be looked at in each and every one of the applicants -- each affiliate application for market-based rate authority.

MS. LEAHY: So, on the second part of that question, the triennial filing should require an analysis of every corporate entity.

MS. GOULET: Absolutely.

MR. PEDERSON: To be perfectly clear on that, some applicants are spread over various control areas that are geographically separate. If I'm hearing you correctly, when the corporation comes and they do an analysis for all areas where they own generation --

MS. GOULET: It may depend upon the nature of the market. In PJM, it used to be a very simplistic analysis. It was a single control area for many, many years. It has recently expanded its footprints significantly to incorporate additional control areas, including some affiliates in those additional control areas. And I do think you need to look at that in a situation where they're all bidding into a single energy market. I think that's part of the key. I mean, that is our experience -- the PJM markets.

MR. PEDERSON: If we had a company, for example, that had generation in PJM and also owned some generation, say, in California, or somewhere in the Western markets, would the proposal be that when the company comes in that they model everything in my example the generation in PJM and the generation in California?

MS. GOULET: I think you could focus on the generation that has the potential to compete in the same geographic market.

MR. PEDERSON: Thank you.

MR. RODGERS: If I could just add some context, speaking for myself, personally, in terms of why I thought this was relevant question to ask. We have some corporate families that have many, many entities within them that have market-based rate authorizations and some of the entities contract very little, or none at all in some cases, for a long period of time.

There's an administrative burden associated with the staff trying to keep track of not only who is due in when, but when an applicant comes in as Jerry was alluding to, which applicants need to be examine as part of a particular applicant's filing. Some market-based rate applicants come in with their whole corporate family to get authorization at the same time while others choose to piecemeal it. seemingly every six months, have some member of their corporate family coming in for authorization. So it's just a question that staff was interested in getting some input on.

Are there any questions from the audience or comments from the audience this morning?

(No response.)

MR. RODGERS: Seeing none, why don't we break and reconvene at 1:15 this afternoon.

I want to thank our panelists very much for an excellent job that you all did this morning. We very much appreciate your coming.

(Lunch recess.)

A F T E R N O O N S E S S I O N

(1:25 p.m.)

MR. RODGERS: I'm not sure if we have a quorum of staffers here to get us launched, but I'm going to try to start anyway. So, if those in the panel could come up to their chairs in the front, I'd sure appreciate that.

The focus of this afternoon's panel is defining of regional markets and defining what is the appropriate mitigation for those that are found to have market power.

Our first panelist this afternoon is Michael Wroblewski the Assistant General Counsel with the Federal Trade Commission. Welcome, Michael.

MR. WROBLEWSKI: Thank you for inviting me to speak at today's conference. Before I begin, I must give the standard disclaimer that the remarks I give are my own and don't necessarily represent those of the Federal Trade Commission or any individual commissioner.

The FTC's experience in assessing competition across a wide variety of industries allows me to bring an antitrust voice or perspective to the inquiry of generation market power.

As both FERC and the antitrust have observed repeatedly, competitive markets are attractive because in such markets private profit incentives are aligned with consumer's interest to increase innovation in what would otherwise occur under a regulation regime. However, it's not in the consumer's interest to allow market participants with market power to be able to price at market-based rates if structural impediments prevent alternative suppliers from providing lower prices or innovative services to customers.

Market power assessments based on economic principles will provide FERC with accurate information on whether to grant market-based rate authority to applicants. The concern about accurate market power assessments is heightened for two reasons in the electric power industry. First, the industry has a long history of horizontal consolidations without effective antitrust review. This occurred because nearly all aspects of the industry were subject to cost of service regulation at the time.

Second, electricity markets lack some of the crucial characteristics that allow other markets to quickly become competitive when market power is exercised. In many areas of the country, these problems include thing such as inaccurate price signals and lack of demand response, severe entry impediments and a complexioned look of transmission structure that makes pricing of transmission difficult. Even absent transmission discrimination, the upshot of all of this is that, if FERC gets it market power assessments right, then it's job of ensuring just and reasonable rates will be made that much easier.

Because the focus of this afternoon's panel is on the defining regional wholesale of electricity markets, I'll limit my comments to geographic market delineation issues.

The framework of the DOJ, FTC horizonal merger guidelines provides an economically appropriate approach for delineating geographic markets on a firm-by-firm basis. Using the merger guidelines framework the relevant inquiry is to delineate the area within which a supplier, a hypothetical monopolist could profitably raise price above the competitive level for the identified product without its customers switching to suppliers located outside that particularly identified region.

Answering this question for the various products an applicant may offer at various times of the day is essential to delineating geographic markets that reflect what actually occurs in the marketplace. Once the geographic market is delineated for each product market, then the tools of market power assessments discussed in the guidelines can be applied sensibly. Without this foundation, market concentration, entry efficiencies and other information cannot be logically assembled and analyzed.

I want to emphasize that any delineation of geographic markets should recognize that transmission constraints are different in different time periods. And that the contours of the relevant geographic market change hourly. As a result, market participants can price those services differently depending upon who is in and who is not in the market at various times of the day.

I also want to emphasize that control areas are unlikely to be the relevant geographic market, except by coincidence. There does not appear to be any economic basis for delineating geographic markets based on control areas. Relevant geographic markets depend on a wide variety of factors that you all know about. Things such as capabilities and the variable costs and available generator units, electrical demands, contractual legal obligations, transmission charges and congestion and utility practices regarding access to the transmission system.

Using a regional approach makes sense if this means that FERC will examine all the applicants for market-based rate authority in a particular region at the same time. Doing so will allow FERC to properly delineate product and geographic markets within that particular region. If using a regional approach means using one geographic region as the geographic market, then I'd say this no more accurate than using control areas as the geographic market for assessing market power.

At the screening stage, FERC may wish to examine frequently reoccurring conditions in various times of the year to delineate geographic markets accordingly. I think what was referred to in this morning's panel as taking different snapshots in different seasons of the year. When FTC's staff has examined electricity and natural gas mergers in the past, we tried to find a manageable number of recurring conditions that provide a proxy to determine if the merger would result in anti-competitive effects under this different group of conditions. Likewise, FERC could define appropriate product in geographic markets by examining transmission congestion, trading patterns, reserve margins, hydrological conditions to construct a group of likely scenarios that provide an accurate picture of whether a supplier or suppliers have market power at various times of the year.

In regions where RTOs or ISOs are operating, FERC should seek to utilize respective RTOs. There actual dispatch model to simulate and help and aid defining geographic markets in areas outside of RTOs, private or commercial computer simulation models that simulate the physical transmission work may be available or FERC should develop its own models for this purpose. These models could also prove useful to FERC in assessing the effects of the post mergers.

Some have asked whether there is a shortcut to assessing market power properly. My answer is no. No one number is going to tell you everything because of the wide variety of products and markets in which an applicant participates.

Thank you for inviting me to participate in today's conference. I look forward to any questions that you may have. Thank you.

MR. RODGERS: Thank you, Michael.

Our next panelist today is Julie Solomon who is the vice president with the firm of Charles Rivers Associates who has been asked to appear today on behalf of the Duke Power Company. Welcome.

MS. SOLOMON: Good afternoon. Thank you and thanks for the opportunity to be here this afternoon. I'm here on behalf of Duke Power, but many of the comments I have today are really much more general. And, from my view, as an economist and a practitioner working in this industry, and market-based rates in particular, over the past decade a wholesale competitive marketplace has grown up in this industry that is fairly robust. It's in every region of the country. It's working reasonably well in most cases.

As a result of this, the market transitioned away from the traditional cost of service, split the service approach, the wholesale trading that was really just between utilities. The one that has many market participants, a variety of products, capacity and energy -- some physical products, some financial products, some paper virtual products. These products are being offered to constantly changing market conditions.

The prices are set in the marketplace and should be reflecting buyers and sellers perception of both the current state and expected future state of the market. When markets are workably competitive, the market should and does have the price for energy. Nobody set the price for energy. Nobody has suggested that these prices are always rational. There certainly have been wide swings in prices, except in some well-known circumstances and somewhat limited circumstances. Most of these price swings can be attributed to conditions in the marketplace -- scarcity, unseasonable weather, demand, forced outages or increases in fuel prices.

In my view, appropriate analyses suggest that an applicant may be able to exercise market power. The proper conclusion to be drawn is that this applicant shouldn't be permitted to set prices in the market. I think it was asked this morning how many people should be allowed to pass the screen. I don't think it's a matter of a number of people. I do think that a screen is, in fact, that. Everybody getting through the screen or nobody getting through the screen can't really be called a screen.

Because someone really has market power, its role should certainly be limited to that of a price taker.

That's consistent with what the Commission had done in many of the RTOs by accepting mitigation plans when they first became RTOs and that are in effect in the RTOs today. In those markets, markets clear at prices that reflect the market conditions, but they're not necessarily the prices that would be established by a bidder who has market power.

The Commission has suggested in those markets that cost-based rates was the solution to drive costs below market. It seems to me that in talking about bilateral markets, and I'm really speaking about mitigation issues, we're a control area utility. And I'll come to whether or not control area is the right market because I certainly agree with you it's not necessarily. When a control area utility is subject to mitigation, it shouldn't be a price setter. The question is, should its prices be set at cost-based rates.

The whole point of having wholesale markets is to try to emulate competition where competition doesn't exist. In my view, setting prices at an artificially or administratively determined below market price or cost there's a potentially significantly interfere with the wise well-functioning market. The utilities required to sell marginal capacity at prices below competitive market price seems to transfer income from one set of stakeholders, the utility and its customers, to the purchaser.

There's also concern of gaming and arbitrage that could lead to a situation where, when market prices are higher than costs, the mitigated party will sell at cost. But, when market prices are lower than cost, the mitigated party has to sell at below costs. They're obviously not selling below variable costs, but selling below costs to recover some of their other costs. The effect of that is potentially non-recovery.

It seems to me that what's needed are mechanisms that enable market prices to reflect prevailing market conditions in the mitigated utility's geographic market, not cost caps that have no relationship to the market. In other words, we should seek mitigation and emulate competitive markets, not regulated markets. There are feasible and viable alternatives to cost-based default mitigation.

This morning some of the specific mitigation alternatives were discussed that more closely related to 203 mitigation -- selling generation, expanding transmission. I tried to focus on other ways of ensuring that prices are not at non-competitive levels. And that's saying can we look at reference prices in neighboring markets. Is there LMP from a neighboring organized market or a published market price for a nearby hub? You may need a basis differential to get what the market price should be in the market in question, but it's not quite as draconian as going back to a cost-based rate.

It's also true that there are published index prices in many markets. Those could potentially be used with or without a basis differential. There may be some administrative issues there because the prices are not only after the fact, that is, after they're published. So there may be some requirement of a clause to adjust the sales terms. Still, there are prices out there that you can look at that occur in markets where there is not market power. I think Steve Henderson mentioned that this morning. You, of course, have to look at a price in a market that's not subject to market power. Alternatively, prices can be set by an independent auction with a control area. This is a process that may work better for long-term rather than short-term solutions.

In looking at mitigation, be it cost-based rates or any other form of mitigation, some of the things that I keep hearing from many of my clients is a need for clarification of what market mitigation is intended to cover. In other words, let's assume for the moment that the control area is the market that we're talking about and a utility is mitigated in that market, it would be helpful to clarify that mitigation only applies to within control area sales to or on behalf of wholesale customers, transmission-dependent customers in that market would otherwise be subject to an exercise of market power.

It seems to me that sales in the control area border that are ultimately delivering an external market. An example is first tier markets where you don't have market power. Those kinds of sales should not be covered by the mitigation. Similarly, if an entity is selling within its own control area for ultimately deliver load external to control area, it does not seem sensible to cover that by mitigation.

This, again, may have some administrative difficulties in terms of information gathering. But it can't be that the intent of mitigation is to provide arbitrage opportunities to intermediaries. That is, that they buy in your market and then resale outside of your market to a customer when sellers are not subject to that mitigation.

To recap, cost-based tariffs may be an appropriate default mitigation, but should only be imposed in situations where the Commission is unable to determine alternative mitigation adequately emulating market conditions. I think another part of that is something that the Commission has heard before and seems amenable to. Mitigation should be determined on a case-by-case basis. A forced mitigation of all one type is not necessarily the solution.

Commenting for a moment on relevant geographic markets, our control area is an appropriate, relevant geographic market. I agree that they are control areas. However, the fact is, in many areas it's much simpler for the Commission and even practitioners and even applicants to have a default market definition. Without that default market definition, a lot of analysis is required to determine the appropriate market. Again, this may be one of those elements there has to be a two-step process screen. Default mechanism is to assume that the RTO is the appropriate market or the control area, depending upon specific situations. But giving applicants and the intervenors the opportunity to identify larger geographic markets or narrower, for that matter, is there's a load pocket.

In doing so, as Michael described, the antitrust test to determine the right market there are some specific analyses that one can undertake to do so. You can look at transfer of capacity. You can look at transfer capacity. You can look at congestion. You can look at trading patterns. You can look at the frequency and severity of transmission constraints, TLRs, whether prices are consistent throughout the region, whether there's a region-wide tariff, whether there is common dispatch. All of these items would be consist with the Commission's practice of aggregating customers for the purpose of defining markets in the context, for example, of a 203 application.

I understand that some parties have made these kinds of representations, but right now I think the hurdle is fairly steep, both for intervenors and for applicants to do markets different from the control area in an RTO. This may be an area that's ripe for doing a little bit of thinking on what kind of hurdles to make that representation.

Ultimately, I do think this is another one that's a case-by-case basis. Parties need to be able to present their own evidence with respect to whether original inquiry is sensible. I totally agree with Michael. If the regional inquiry merely states that the market is the region, it's not really an inquiry. If, however, it's more convenient for the Commission to aggregate applications to look at a particular region and decide what markets are relevant within that region, there is an opportunity to do that.

But, again, it seems to me that the default mechanism of control areas or RTOs is administratively simpler for applicants and for the Commission in the absence of doing such.

Thank you for the opportunity to be here and I'm happy to answer questions later.

MR. RODGERS: Thanks very much, Julie. We appreciate your remarks.

Next, we will hear from Matthew Morey with Christensen Associates here today representing NRECA. Welcome.

MR. MOREY: Thank you very much, Steve. Thank you Commissioners and Commission staff for giving me the opportunity to participate in the conversation this afternoon.

Yes, indeed, I am today here representing NRECA, the National Electric Cooperative Association. I might offer the disclaimer, once again, that because of the differences that various members in NRECA have who stand on both sides of this issue. In this instance, it seems to me that I'm in a position to state my perception of these issues and these are my opinions, although I wouldn't be here today if these opinions were generally agreed to by NRECA's members.

With that said, I begin by suggesting that I thought that the panel's focus today, as a result of the questions posed by the Commission, was on the issue of whether or not the Commission itself could initiate a regional analysis. Actually have the Commission staff conduct a regional focused analysis and whether or not that analysis would compliment anything else that was being done.

With that in mind, I'll proceed along those lines, although my remarks reflect purely my views as an economist, I think the Commission has focused the panel's attention correctly on a very major issue -- how best to define the geographic scope of electricity markets outside of RTOs or ISOs and whether the Commission, in fact, should analyze the competitiveness of the market rather than whether individual firms have market power.

Before addressing this, however, I need to point out -- I believe this is true -- the issue of whether there should be a market power analysis conducted within the context of RTOs and ISOs should not be taken off the table. I don't think one would necessarily get a pass on market power issues if you're a member of an RTO or ISO.

First, some general comments to kind of lay the foundation and perspective for some of the answers I've provided to the questions supposed to the panel. The geographic scope -- you've heard others say this as well. the geographic scope of electricity markets depends on physical factors, transmission constraints that limit simultaneous import capability and institutional factors -- seams, transmission rate pancaking and a host of other issues. Julie alluded to a number of those that have an impact that limit the geographic scope of competition.

These two sets of factors at the very least should be at the top of the focus of the Commission's policy reform. Removal of these impediments to the extent economically feasible may be the most significant step the Commission could take towards establishing or towards addressing these vexing market power problems. The analysis of competitiveness of geographic markets and the analysis of market power of individual competitors in those markets must therefore take both the physical and institutional factors into consideration in defining the relevant geographic markets.

This may mean that the regions as initially defined, even if defined larger than a control area, you might agree that the default control area definition is not correct. Even if they're redefined in some broader way, we still have to consider that we may have to focus attention on subregional markets in the first cut because physical institutional factors create import limits that make them the smaller subregion for relevant geographic markets for analysis.

In any event, the Commission should analysis the competitiveness of each region and relevant geographic market as defined by the limiting factors. If the Commission finds the market is not competitive, for example, it's got load pockets or other problems, it should analyze the individual entities participating in those markets that are likely to have market power in that relevant geographic market.

I believe with the preceding two speakers and with, perhaps, others to come after here, I believe there are advantages to doing the regional market analysis, competitiveness analysis. But I think we need to first define what we mean by regional market approach here. I believe in the context of the test year. However, you're going to define that a regional market approach is really a process that would run kind of as follows.

The process begins with an assessment of the competitiveness of each region, which really involves also an analysis of the structure of that region. The setup in that region because power system conditions in particular transmission constraints change from hour to hour. As we all know, this assessment should be developed for a sample of seasonal peak and off-peak periods. We had that discussion earlier today as well. I think, if the regional market is found to be competitive in all sample periods, according to whatever metrics and whatever thresholds you want to impose, the process, it seems to me, would be complete. If the regional market is not found to be competitive, it is necessary to identify the particular entities that might possess market power and take steps, if necessary, to mitigate that.

The Commission has already noted there are several advantages to doing a regional approach. I think the most important is the ease of administration and the consistency with which you could treat individual market participants within a region. Consistency, I think, has some value. Assessment of regional competitiveness could be performed a single time for each test year rather than over and over again for each applicant for market-based rates. The data could be obtained. And here's where the resistance from the staff I can appreciate. I was talking with Steve earlier about this. The data could be obtained from all entities at the same time, thus, substantially reducing data gathering problems. That's a lot of data that you already possess and allowing the data to be collected on a consistent basis as defined by the Commission, and with what I would consider to be an appropriately uniform level of detail. The regional market approach can therefore reduce administrative costs for both the Commission and market participants as I see it.

Furthermore, a first-step analysis of market competitiveness could be consistently applied to all applicants for market-based rates in the region. I don't really see any significant disadvantages provided that the analysis is conducted at a sufficient granular level. I don't think that you can just run an HHI for a large region and leave it at that.

What would be required to implement the regional analysis? I think there's four tasks that you have. You've got to define the markets to be analyzed. You've got to define the market power tests and the competitiveness analysis or screens that you would apply, identify the data required to implement those tests and specify the time periods to which the analysis applies, the dates by which all suppliers need to provide data to the regional market monitor, which I assume in this case would be the Commission. And the dates by which the regional market monitor will provide results to all parties.

I don't think that the Commission should shy away from developing a market power analyses to the extent needed that require increased collection of data from public utilities or, perhaps, engaging in more ambitious examination of the interim screens or variations on those. The Commission, I think, of course, must ensure that it has adequate staff and resources to make effective use of the data and to conduct these analyses. But, somehow, I don't see that as a major challenge. What factors should be considered to demonstrate a relevant geographic market is broader than a control area.

Once again, you go back to the issue of the geographic scope of each electricity market is defined primarily according to prevailing transmission constraints.

Secondarily, according to any institutional factors or structural factors that limit the geographic scope of the markets.

So what elements do buyers believe are necessary for a market to be competitive? We don't need to take a lot of time to go into that. Buyers need access to the supplies of many suppliers. That's what we're talking about. When there are import limits and constraints in the region and supplies are limited, we're looking at a situation that clearly violates the situation we're looking for here.

Can a competitive market finding be compatible with the finding that competitors possess market power? In general, I don't think you can find that the market is competitive and find that you've got market power problems to the extent that the analysis is imperfect. The fact that you've got imperfect data, data limitations and the testing screens themselves are imperfect, it seems to me it is probably possible in practice to find that you've got a competitive market under one set of screens and find that you actually have certain participants who have market power.

I think the most important thing, though, is that the converse is also possible. Analysis could find that the region is non-competitive. But you could also find the individual competitors do not possess market power. So you obviously have to be careful about examining individuals within the market in order to determine what's going on.

If the region were found to be non-competitive, how will the interest of buyers and sellers that do not possess market power be protected? It is primarily the consumers that we're interested in protecting here, but there's no question that the buyers or rather the sellers who do not possess market power should be protected from intrusive regulation and regulation which would tend to, I think, do more harm and distort a reasonably well-functioning market. As Julie was indicating, I think that one has to be careful about that.

What types of generation market power mitigation can the Commission consider besides cost-based rates? In RTO administered short-term market, it should be sufficient for suppliers with market power to have their bids limited so that prices or constraints are just and reasonable levels. By that I mean levels that would include verifiable incremental costs of commitment and dispatch. And that would not necessarily induce with holding of supply. In other words, don't intervene in a market that creates more problems than it actually solves.

In long-term contract markets, however, and in non-RTO markets in general, I'm not sure there's a real obvious behavioral alternative to cost-based rates. It certainly possible to explore them. Julie suggests some options, but I think the cost-based rate is clearly the reference point. That's where we start. In all cases there is, of course, a structural alternative. It involves horizonal division of generation ownership. But I'm not recommending that the Commission consider that.

With that, I will close. I thank the Commission for the opportunity to talk with you today and I look forward to further questions. Thank you.

MR. RODGERS: Thank you very much, Matthew.

Our next panelist today that we're going to hear from is David Mills, the Director of Power and Gas Supply Operations with Puget Sound Energy. Welcome, David.

MR. MILLS: I'd like to thank the Commission for this opportunity to address the issue of defining the appropriate market for purposes for assessing generation market power.

My responsibilities at Puget Sound Energy is that I'm responsible for the day-to-day short-term operation of the bulk power supply portfolio and the natural gas portfolio as well as the wholesale market transactions that allows us to reliably meet load.

My comments this afternoon will be directed to the tasks of correctly identifying the appropriate regional market in the Pacific Northwest to be evaluated under any market screening test in the Northwest. I believe there's ample evidence that applying such screens to control areas has little meaning if we're seeking to identify market power. I will also discuss the problems created by defining the market too narrowly, particularly, in the Pacific Northwest and will make recommendations as to factors to consider in defining the appropriate markets.

Given that my comments today are specific to the Northwest, I thought a little background would be in order since it's about a five-hour flight. The Northwest as I'm going to talk about it today is composed of the states of Washington, Oregon, Idaho and western Montana. This geographic area has an annual average load of approximately 20,000 average megawatts.

Puget Sound Energy is a dual fuel investor-owned utility located in western Washington State. We serve about a million electrical customers and 800,000 natural gas customers. By contrast, our average annual load is about 2800 average megawatts. Like many of the Pacific Northwest investor-owned utilities, Puget is a net short utility, meaning we are a net purchaser in the wholesale market.

For example, last year we met our retail demand through a combination of our own generating resources, totaling about 27 percent, reliance on long-term purchase contracts for about 42 percent and the residual of about 31 percent. We had to go to the market to purchase. As a net purchaser, we are reliant upon a robust and competitive wholesale market. We have a substantial interest in ensuring that the Commission is using an effective market power test that is neither too tight nor too loose.

One other not so subtle nuance with the Pacific Northwest we are also home to the Bonneville Power Administration. BPA not only serves 40 percent of the region's energy needs, they also own and operate about 75 percent of the region's high voltage transmission system, which equates to about 15,000 circuit miles of high voltage transmission. By contrast, Puget Sound Energy transmission business, we own and operate about 2400 circuit miles of high voltage transmission.

The distinguishing characteristic of the Pacific Northwest is the connectivity of our control areas, especially, given the dominant footprint of BPA Transmission. In the Pacific Northwest control areas utilities are essentially embedded with NWPA control area. This is significantly different than many other parts of the country where control areas can theoretically be considered as sequential, essentially creating a train of transmission providers between the point of generation and the point of final consumption.

I'll get back to those geographic points and why that's important for defining the market, but I thought we'd give you four specific factors to consider before I come right back around and answer.

First, are there wholesale loads embedded within the IOU control area? Second, is the regional transmission infrastructure robust? Third, do wholesale occur within the IOU control area? And fourth, are there regional trading hubs? And, if they are, are they liquid and transparent with respect to price discovery? Given these factors, I believe the relevant market in the Northwest should be the entire Northwest market and not the individual control areas.

Why are the control areas in the Northwest not the market first? Few, if any, wholesale utility customers are embedded inside of the IOU control areas. And, in my utility's case, there are none. I will assert that on many fronts the Pacific Northwest already functions similar to an RTO. We have a very robust transmission grid. We have a single dominant transmission provider to which all utilities are interconnected. We also have a robust regional energy and transmission planning process. There are no wholesale utility customers dependent on any IOU for transmission as all are connected through BPA with access to the liquid trading hubs.

Last, the bulk of the wholesale power

transactions are executed at those established trading hubs and not within an IOU's control area. The technical challenge that we face currently on the current screen as applied to the control area level in the Northwest is that generation within our control areas is often substantially less than load regardless of season. The import capability into our control areas, because of being basically surrounded by Bonneville, is often substantially greater than our load. And, as what we're finding out right now, Appendix E does not yet address these circumstances.

With respect to the competitiveness our market, I already alluded to the fact of Bonneville's presence. We're also highly hydro dependent. About 60 percent of the region's energy comes from hydroelectric generation, but it's this transmission interconnectiveness that's key. Specifically, trading is not conducted inside our control area, but it occurs at several liquid and transparent trading hubs. The first and most important of which is called the Mid-Columbia or the Mid-C hub. This is essentially 118 mile virtual bus that connects several federal and municipal hydro projects in central Washington State. This is the primary trading hub in the Northwest. It is also the price discovery point of reference for all entities to run their thermal generation. You use a mid-C price against, say, a C-mid gas price.

Two other secondary hubs I need to bring up -- the California/Oregon border, the COB hub, which is the interconnect through the Northwest. It's an AC interconnect between the Northwest and northern California and the Nevada/Oregon border or NOB, which is the DC interconnect between the Northwest and southern California.

While these lines provide some opportunity for surplus sales north or south, the big advantage to these lines is that it allows the West Coast to capitalize on the seasonal diversity between the winter peaking northwest and the summer peaking southwest less I leave you with the impression that there is substantial pricing transparency for those traded at the Pacific Northwest hubs. Specifically, we now have both a daily and an hourly published index.

In the attachment, I've included a slide here labeled "Pacific Northwest Transmission Interfaces." The reason I've done it is that I want you to note that all control areas of the investor-owned utilities are either directly connected to one or no more than one BPA wheel away from the mid-C trading hub -- the primary trading hub of the Northwest.

The vast majority of the transactions in the Northwest are executed at these hubs and there is a heightened degree or a high sense of price transparency.

The vast majority of those transactions are now using a standardized power sell contract. It performs two functions in the marketplace, which I tried to replicate.

(Slide.)

MR. MILLS: It allows entities such as Puget Sound Energy and other IOUs to transport generation from our distant resources directly to our load. Second, transmission products available from Bonneville Power Transmission allow for efficient transmission of both generation and market purchases throughout the Pacific Northwest. In fact, many BPA transmission customers have network-type agreements that allow them to move energy virtually anywhere within the Bonneville system without regard to point of receipt or point of delivery.

Since I don't do this for a living, I'm glad this is the last slide.

(Slide.)

MR. MILLS: The vast majority of wholesale power transactions in the Northwest are executed at one of a small number of established liquid trading hubs, not within a control area. All wholesale utility customers are directly connected through BPA through to those regional trading hubs. In these circumstances, the relevant market for determining market power of Northwest utilities should be the entire northwest market, not individual control areas.

Lastly, there are adverse consequences to both the competitive nature and the market participants if the incorrect market is targeted. Failure to pass a specific screen results in a public announcement of the same, whether it's public, official announcement or word on the street, which immediately impacts liquidity of both a specific entity and for the broader regional market.

As mentioned previously, Puget Sound Energy and other Northwest utilities are net short and net purchasers in the regional market. These types of investigations or concerns about failure to pass a market screen test usually result in two very quick and immediate reactions from the market -- a reduction in the open trade credit that is extended to the purchaser that is in a net short position. And two, a reduction in the tenor or the time line that counter-parties are willing to enter into transactions with that parties. These create serious risks to the utility from both an economic, and more importantly, from a reliability perspective and underscore the important of defining the right market for the purposes of assessing generation for market power.

Thank you for this opportunity to address the panel and the Commission. I look forward to further discussion. Thank you.

MR. RODGERS: Thank you very much, David.

Before we go to our next panelist, one housekeeping matter I wanted to mention. Several of the panelists, both from this morning and this afternoon's panel, have provided some helpful written statements as well as some Powerpoint slides that Mr. Mills provided. If I could ask all of you to please e-mail a copy of your presentations to Kelly.perl@FERC.gov. She'll make sure those get posted on the Commission's website so those that don't have access to hard copies here can have the opportunity to see those -- helpful information.

Thank you again. That's Kelly.perl@FERC.gov.

Our next panelist this afternoon is Bob Weishaar with the firm of McNees, Wallace & Nurrick, who is actually holding two hats on his head today representing the Southeast Electricity Consumers Association and also the Louisiana Energy Users Group.

MR. WEISHAAR: Thank you, Steve. Thank you Commissioners and Commission staff for the opportunity to speak today.

I'm going to bring you back across country and focus on the Southeast for the moment in the context of this generic rulemaking.

By way of background, I am speaking today on behalf of my clients. SeCEA is an ad hoc coalition of large industrial customers with facilities in several southeastern states, including Louisiana, Alabama, Mississippi, Georgia, Arkansas and the non-ERCOT portion of Texas.

LEUG, the LEUG, is a coalition of industrial customers focused exclusively on Louisiana. When we compiled our comments today, we tried to focus on the questions the Commission posed in its supplemental notice. Our approach is to go through those seriatim. At the end, I want to offer a little bit of a "from the trenches" perspective from some of the industrial customers in Louisiana and what they are seeing in terms of this issue.

On the issue of regional market approach, theoretically, applying a regional approach to analyzing market power would provide a more complete picture of the competitiveness of markets. However, and this is a big however, this can only be done by carefully considering the impediments that exist within that region that could inhibit a market from being truly regional.

Some of the things that come to immediate mind include transmission rate pancaking, the uncoordinated provision of transmission service by multiple transmission providers, the lack of independent transmission providers and the lack of an active, robust market monitoring scheme. The impact on generation market power within a region of some or all of these factors may be difficult to quantify. Therefore, from our perspective, in order to err on the side of caution in terms of ensuring just and reasonable rates, we think it is necessary to continue an approach under which market power is evaluated on a subregional basis no larger than a transmission provider control area.

For example, in regions like the Southeast where an ISO or an RTO has not been established, it is especially important to analyze the market power inherent in a single utility or a single state subregion where the likely exercise of market power inures to the disadvantage of potential suppliers and customers alike as a threshold issue and this is a point that we like to emphasis. A competitive market structure must exist before the Commission goes down the path of analyzing market-based rate authority for individual applicants.

Based on our experience over the past decade or so in which market-based rate authority has been in place, it appears that the cart may be well out in front of the horse. We think that in order to satisfy judicial requirements the Commission has to take at least three steps.

First, the Commission must establish benchmarks against which it will judge whether the structure and dynamics in particular area are sufficient to be defined as a "competitive market." Second, the Commission must analyze whether its defined relevant area, in fact, meets or exceeds that benchmark. Third, and this is critical, the Commission must continually monitor that structure in each of those areas to ensure that it continues to meet or exceed that benchmark. Mere presumptions of competitive market conditions cannot suffice to protect customers.

We think a competitive market can exist. And, in fact, competitive market conditions could exist where players have a combination of market-based rate authority and cost-based limitations and a combination of cost-based and market-based pricing provides no grounds, however, for any relaxation of the Commission's active, ongoing monitoring of market participant behavior. I sometimes analogize this issue to kind of rocks on top lava. If you have one crack in the rocks, the lava starts spewing. Spewing lava is not a good thing.

The question is, if a region is found to be non-competitive, what should the Commission do to protect the interest of buyers and sellers? If a region is found to be non-competitive, our position is that cost-based rate caps for generation must apply in that region. We think the Commission has no other statutorily permissible option. We do know that cost-based rates satisfy the just and reasonable standard of the Federal Power Act. What we're here today to discuss and what we continue to grapple with is what amount of market-based rate authority can also satisfy that standard?

A couple of comments specifically on behalf of the LEUG members. It's, I guess, from a "from the trenches" perspective in dealing with the particular utility to which LEUG members are interconnected. It goes back also to structural issue of do we have a competitive market structure? Is the structure itself delivering the benefits that are expected of a competitive market structure?

I would not, if you take the average annual cost of electricity for a 50-megawatt high load factor customer, in Entergy's Louisiana territory, the annual cost is about $19 million. If you take that same customer, same facility and situate it in the areas adjacent to the West, the cost would be $15 million. If you take the same customer and sit it to the areas to the East, the cost would be $14 million. A substantial price disparity for industrial customers. The same industrial customer in what someone defined as a region. There are a number of factors that address that. I think the structural issues are paramount. I think the transmission access issues, data transparency issues, generation market power all come into play, but it is a telling statistic, I think, in terms of where we're headed.

That concludes my remarks. I have additional information that I can interject in response to questions, but I'll leave it there for the moment. Thank you.

MR. RODGERS: Thank you, Bob.

Our next panelist is Michael Beer, Vice President of Federal Regulation and Policy with LG&E Energy.

MR. BEER: Thank you. Good afternoon, Commissioners, staff. It's a pleasure to be here to address both you and this panel this afternoon.

By way of introduction, LG&E is the holding company that operates two integrated utility companies that serve both retail and wholesale customers, primarily in the Commonwealth of Kentucky, but we have a limited number of customers in Virginia and Tennessee as well. The combined companies own approximately 7665 megawatts of net base load and peaking generation facilities.

Louisville Gas and Electric are LG&E and Kentucky Utilities are KU. Both operate under the regulatory authority of the Kentucky Public Service Commission in a non-retail access environment as such. All capacity constructed and operated by the two companies is justified solely on the basis of serving the needs of firm native load customers on a least cost basis. In Kentucky, this firm native load obligation effectively extends to 13 municipal electric systems that are also served by KU under FERC-approve long-term cost-based contracts that have five-year termination provisions.

Thus, in the context of this proceeding, it can be posited that, at the very least, the geographic definition of the default market should be clarified to recognize firm native load as including wholesale load, which is treated equally with retail native load in the eyes of both the company and the state Public Service Commission.

As I said a moment ago, all of these resources are included in the Kentucky jurisdictional rate bases of LG&E's two utility companies. The capacity costs associated with these units are therefore recovered in their entirety from the retail and wholesale customers that make up the utility's native load. The company's combined fleet of generation is only large enough to serve the utility's peak native load, plus the required reserve margin. This fact is critical because at no time have either of the utilities planned for or constructed new generation for any purpose other than fulfilling their statutory obligation to serve their native load customers at least cost.

It is only during periods when certain units are not fully needed to serve native load that the company seeks to maximize the value of this temporarily available energy through short-term, non-firmed sales into the wholesale energy spot market. Any margin realized on these sales flows entirely back the utility's native load customers and serve to reduce the revenue requirements associated with these units.

LG&E believes therefore that as a threshold matter it is inappropriate to subject this capacity so dedicated to serve native load to any type of market power analysis or mitigation. Energy sales are intermittent, short-term non-firmed economy exchanges. The long-term availability of which should not be relied upon by anyone in the marketplace.

Having outlined the case for excluding certain capacity from any type of market power analysis, let me address the broader question for the day. FERC's April 2004 adoption of indicative price screens for determining market power potential has caused great concern with LG&E as well as many others in the industry. I'm going to focus on two issues of particular concern to LG&E.

First, LG&E believes that the indicative screens fail to paint a true picture of the marketplace in which the subject entity operates. Second, there is a great need for FERC to refine its tests to provide greater guidance up front as to whether an entity will ultimately be found to have market power.

As with regard to my first point, I recognize that many parties have commented that the indicative screens fail to accurate portray the potential for an entity to exercise market power. LG&E agrees with many of these comments and strongly believes at the very least the screens must be refined to more accurately reflect the realities of the marketplace. Such analysis at the end of the day must incorporate specific reality-based considerations in measurement of market power, must target customer-specific concerns and recognize the obligations of buyers to properly plan their procurement strategies.

It is imperative that in addition to creating screens to identify possible market power. FERC also review what mitigation procedures are already in place, including both de jure mitigation by state commission and contracting parties and de factor mitigation that requires FERC to examine the circumstances of actions that have prompted the filing of a complaint.

In particular, LG&E believes that the screens as currently formulated only tell half the story of the marketplace. The amount of generation that a seller owns or controls beyond the needs of its native load is only half of a larger equation. The other half is how much energy potential customers demand or might demand. In this regard, I believe that the concept of contestable load analysis discussed by several utilities, including LG&E in their updated market power analysis filings warrants careful review and consideration by the Commission. While any screen or test will likely over or under represent an entity's ability to exercise market power, the failure of the current screens to consider how much potential wholesale load is in the marketplace is a gross shortcoming.

Along these same lines, the second factor that any screen or test must take into consideration is the geographical location of the actual demand. Most of LG&E's short-term wholesale energy sales occur at a generation bus within the LG&E control area. None of these sales however sink within the LG&E control area. Rather the customer wields this power outside LG&E's control area where even FERC's indicative screens shows that LG&E lacks market power.

It is the sink area that should be the geographic area of interest for this type of transaction. A location of the source of the power should not be a part of the analysis. Again, the issue here is that FERC's market power screens test must look at the demand side of the transactions at issue.

My second major point today is the need for greater up front certainty as to whether an entity will ultimately be found to have or lack market power. While I appreciate FERC's desire to keep its market power tests flexible so that entities can demonstrate that, notwithstanding the screen failure, the opposite true. Such flexibility also creates uncertainty. This is harmful to the market.

That said, whatever test or tests FERC ultimately uses must contain an option for entities to demonstrate that notwithstanding any failure they lack market power. Under the current screens however too many entities are failing, creating too much uncertainty in the marketplace. Almost every vertically integrated utility has failed one or both of FERC's indicative market screens in its own control area.

I expect that as FERC looks beyond these screens at the actual facts in the marketplace, such as by looking at contestable load, FERC will find that many of these entities lack the ability to exercise market power. It is antithetical to the concept of promoting dynamic markets for wholesale power however to leave so many entities in limbo with refund liability for market-based sales for the period of time that it will take FERC to make a final decision as to whether an entity has the potential to exercise market power.

Market participants need more certainty as to their regulatory status if they're going to enter into short, or particularly, long-term power sales transactions in an effort to keep the wholesale markets moving fluidly. Accordingly, in fashioning future tests for market power, FERC should focus its tests more so as to not over capture potentially problematic situations and historical market dynamics.

Thank you for your time. I would welcome any questions when appropriate.

MR. RODGERS: Thank you, Michael. We appreciate that.

Our final panelist this afternoon is Robert Stibolt, a senior vice president with Tractebel North America here today representing EPSA. Welcome.

MR. STIBOLT: Thank you. I'm very honored to be here on behalf of EPSA. I did submit a prepared statement. I believe it has been submitted electronically. So I will simply hit the highlights contained therein.

The issues we're dealing with today, in my view, are very difficult, challenging issues. It tends to leave me feeling like not much of an expert, but I won't let that stop me in terms of trying to offer some comments here and maybe hit a few of the high points.

Generally, my responsibilities are focused on helping to run a business day-to-day, including the portfolio management and risk management function. So I haven't really focused on studying various alternatives for screening market power. There may be some very good alternatives being raised. But my reaction is that the interim screens seem very reasonable to me based on a number of considerations.

I think maybe the most important is a view I have about what the natural market structure of power generation should be. My view is that it is a competitive market structure. I really base that kind of on a number of observations.

First of all, if you look at the scale of capacity increments relative to the scale of the relevant regional market, there's no economy of scale in power generation. In fact, I would take the position, I think, there are actually some possible dis-economies of scale based on some portfolio management considerations along the lines of what we've seen occur in the oil and gas sector as well. I think that had some implications on what we might expect in terms of future evolution of competitive generation markets.

Certainly, the evidence we've looked at Tractebel has generally suggested no correlation at all between scale and success of the business, either in the energy marketing of the generation sector. So I think a market structure with a lot of competitors is a sustainable market structure. My view is I would expect it ultimately to look a lot like natural gas production. For example, there I think we see -- you look at various times in history, but you'll see the largest player having something like a 7 percent market share.

All told, I think if somebody can't pass the

20 percent test or the pivotal supplier test, it says to me it's really time to ask some tough questions about that. It's not to prejudge what the structure of the market should be, but it just seems to me that it needs to be investigated in terms of the extent of the market, in terms of how to define it. I think there's a lot ambiguity there, but I tend to work backwards, maybe to get my hands around the problem.

Clearly, if I have two regions and there's absolutely no power flows at any time between those two regions, I would view those as clearly distinctly separate markets. To the extent that you see some power flows between two regions, you might argue that they're starting to look more like an integrated market than two markets. And then at some threshold I think you would conclude that they really are, in effect, one market.

I can't tell you what the appropriate threshold should be and I suspect it's a matter of judgment, but that's the way I would approach the problem. I would tend to think it's bigger than a control region or a control area, but certainly much smaller than a NERC region. I would also agree with the view, and I think it's implied in my written comments, that the other three prongs we've talked about still need to be addressed and need to be a focus of the Commission, certainly, vertical market power barriers to entry, especially, transmission barriers. And utility affiliate abuse do continue to be significant issues that I think need to be addressed and I think can be addressed.

I'll also go on record in terms of maybe some of my training in physics. I subscribe to the view that energy and momentum are conserved. I also tend to take the view that power does not flow away from load. So the problem of serving load is really one of assuring adequate regional resources to serve that load. It could be local generation. It could be adequate transmission with adequate resources in an adjacent region, although I think we saw maybe with the California experience the danger of relying on simply supply from adjacent regions.

I look at some of the proposals that are being considered in PJM, for example, the locational and stalled capacity concept strikes me as a very elegant solution to a mechanism to ensure that there are adequate regional resources and it may be a mechanism to help promote the unbundling of supply or generation, which, again, I think can be a very competitive solutions from some of the other aspects of transmission serving load.

So I think those are the highlights of my comments. I appreciate the opportunity to be here. Thank you.

MR. RODGERS: Thank you, Robert. I appreciate that.

I had a question, I guess, to kick us off here for Mr. Beer. If I understood your testimony this afternoon, you felt generally that capacity then had been built for the purpose of serving native load, should not be counted in the wholesale market test the Commission has. Is that correct?

MR. BEER: That's correct.

MR. RODGERS: I guess what strikes me as curious about that or what I have a question about that on is, if, in fact, that same generation, say, for half the year is being used to make wholesale sales in our markets, markets that FERC regulates, why should we just ignore that? Regardless of what the generation was built for, why should at FERC just generation that is, in fact, by your own admission, competing in wholesale markets?

MR. BEER: It's energy that is available off of capacity that is entirely dedicated to native load purposes. The availability of that energy is wholly unreliable for anyone to conclude that they could call upon that in the marketplace at any time.

MR. RODGERS: I guess I would ask what your definition is of "wholly committed" because you said that the capacity is wholly committed to native load markets for serving native load. It seems to me that that is not the case. In much of the year that capacity is, in fact, not dedicated, committed, devoted to native load. And, in fact, it's free and available for other purposes.

MR. BEER: I would respond by saying that native load has a first call priority on that capacity. That's why any sales of energy have to be short-term, non-firm because in the event that something would arise through lose of a unit or some other contingency that capacity would be required to serve native load. It would go to serve that native load as required.

MR. RODGERS: We had a panelist back here in June who suggested that because it's so hard to split the use of capacity for wholesales versus native load purpose that maybe what the Commission should do is just let market-based applicants propose to the Commission what portion of their capacity is devoted and dedicated and committed to serving native load and the Commission should just take them at their word for it and not let them make any wholesale sales from that generation. Because, in the applicant's own admission, it is devoted and committed and dedicated to native load. What's your response to that?

MR. BEER: This may get into, I believe -- one of the panelist earlier this morning alluded to this somewhat and there was some discussion about the need to, perhaps, look at and it requires more case-by-case analysis. But this is an instance, perhaps, LG&E creates a situation or presents a situation, perhaps, that does call for examination of where those sales may take place.

In our particular situation, as I said, there is virtually no contestable load within our control area. So irrespective of whether energy sales off of our capacity would be subject to a market power analysis, the simple fact is those sales will sink somewhere other than our control area in areas where we admittedly lack market power, even by the screens that are currently in place. It may be something of a distinction without a difference when you look at our unique situation.

MR. RODGERS: Jerry, did you have a question?

MS. PERL: Mr. Beer, to pick up on what Steve is saying, a couple of questions. Do you know how much sales -- wholesale you make outside any control area anyway?

MR. BEER: In terms of dollar revenues?

MS. PERL: Dollars, megawatts, whatever.

MR. BEER: I should have that at the tip of my fingers and I don't.

MS. PERL: Is it trivial or does it contribute enough to your bottom line so that you would worry about it?

MR. BEER: It's something we definitely would worry about. We have embedded in our base rates an off systems sales credit that serves as a reduction in the revenue requirement for our native load customers. But, again, those sales are sink outside of our control area.

MS. PERL: It looks like your control area does not have a wholesale market, will not have a wholesale market and that's the way it's probably is indefinitely. If there were to be a termination -- okay, your market-based rate applies only outside your control area and only to sales and only if we're satisfied that the ultimate consumers -- it is, indeed, truly sinking outside the control area. Would that be an authority that would satisfy you?

MR. BEER: I can't sit here and commit the company to your hypothetical, but your situation, I think, is something that would certainly go a long way to resolving many of the concerns that we have today. We have no such sales that sink within our control area. The concern to us is loss of market-based sales authority -- market-based rate authority at our generation would cause us severe problems.

So, to the extend that for those sales that sink outside of our control area, if you look at the destination and not the origination point as being determinate of the question, that certainly is something that I think we would find favorable.

MS. PERL: Do you know where you sink? What regions? You're almost surrounded by PJM at this point, so would it go through PJM?

MR. BEER: Correct. PJM, MISO, TVA is to the south.

MS. PERL: There's no incentive for any reimportation outside of either -- you're pretty much off by yourself. You sell and there's nobody buying.

MR. BEER: That's correct. We are not a net importer.

MR. RODGERS: Mr. Beer, maybe I'm misunderstanding part of your point here. Under the interim screens the Commission adopted in the April and July orders, if you fail in your home control area, but you want to make a sale into a first tier market and you pass on that first tier market, in other words, you are found not to have market power in that first tier market, you can still make that sale into the first tier market at market-based rates even though you have market power in your control area in that hypothetical.

MR. BEER: The concern, though, I guess is how you define -- it's that point at which title transfers. If we are transferring title to that energy, to the buyer at our bus, then our concern is that that market-based sale would be occurring within our control area, even though it's ultimately sinking outside of the control area. That is the source of our concern.

MR. RODGERS: Okay. I also had a question for Mr. Beer about something else you had mentioned.

You had commented on the very flexibility that the Commission has afforded market-based applicants and the screens creates uncertainty that hurts the market. I can appreciate why that might be so on the one hand. But, on the other hand, I know the Commission has been criticized for some time under the old SMA screen that we did not provide enough flexibility. So it seems on the one hand the Commission is cursed either way it goes on this issue.

If we try not to have one-size fits all approach and fit everybody into one neat box, but instead recognize that there are regional differences in different parts of the country, recognize that there is not just one way of defining markets that always works in all situation, therefore we need to have flexibility, recognize that not one type of mitigation always works for every type of market power problem and thereby give applicants flexibility to propose mitigation, naturally, by definition, that is going to create some uncertainty.

I guess I'm not really sure what it is that you're suggesting that the Commission should do to address this problem.

MR. BEER: I think the point there, and please don't misunderstand me. I don't want to go on the record as saying flexibility is a bad thing because it isn't. In this particular situation where a vertically-integrated utility in a non-retail access state knows that it is going to fail all of the screens until you get to the point where it can demonstrate by some other means that it can't exercise market power, the point is let's eliminate that regulatory lag and the uncertainty involved in that process and go immediately to the last phase first.

If we know that we're not going to be able to satisfy the process up until the very end, then allow us to go ahead and propose whatever mitigation measures may be available to us, thereby eliminating that lag and eliminating that interim uncertainty where we may be subject to refund liability.

MR. RODGERS: Again, I'm not sure that I'm necessarily understanding all of your point, but I would read the Commission's April and July orders as allowing applicants the flexibility to propose mitigation at any point in the process that market power problems are indicated. That's my opinion. But, anyway, I'm not sure if that goes to your question or not. Please correct me if I'm missing the point on your question.

Jerry, you had a question?

MR. PEDERSON: I have a question for Mr. Morey.

If you could clarify something for me.

When you were speaking about regional markets, and if the Commission had found that a regional market was non-competitive, I thought I heard you say that in that instance when the Commission finds a region is not competitive that it would be odd that some sellers would be found to be competitive within that region. Do I have that backwards?

MR. MOREY: I think, perhaps, there was some confusion there, maybe due to the statement that I made. If you found the market was non-competitive, I believe it's certainly conceivable that there are particular suppliers within that market who do not have market power. You could examine individuals within a non-competitive market and find that some of those entities do not actually have market power.

But, of course, if you found the market to be non-competitive, there must be some entities within that region, however that's being defined, who have market power. Otherwise, you wouldn't find that it was non-competitive by definition.

MR. PEDERSON: Does the reverse of that work as well? If the Commission found that the region was generally competitive, but maybe there were one or two suppliers in there that, perhaps, were not competitive, could that situation occur as well?

MR. MOREY: It's conceivable. Yes.

MR. PEDERSON: And the response to that would be to mitigate, in my example, the two sellers that are not competitive.

MR. MOREY: I think that's the step you would have to take. You'd have to consider how you'd go about disciplining that market power.

MR. PEDERSON: Thanks.

MR. RODGERS: Marybeth, do you have a question?

MS. TIGHE: Thank you.

Today, we have moved away from sort of the traditional market participant who owned and operated their own generation plant to situations where you may have multiple owners of a plant who turn around and contract to third parties fuel procurement operations, marketing risk management -- a whole variety of functions that go along with operating a power plant in a market. For those of you on the panel who have seen advantages in the regional market approach, do you see that approach having any particular advantages to dealing with this new emerging type of market participant or disadvantages?

And, for those of you who seem to be feeling that the regional market approach doesn't have any greater benefits than the current type of approach, do you see a similar question? Do you see some particular advantages of the current approach in looking at market power issues with these new type of market participants or disadvantages of the current approach in looking at this new type of market participant?

MR. WEISHAAR: I would like to venture an answer at some point, but I think I need a little more clarification of the question. Are you talking about the potential of using a tolling agreement type approach as evidence that the entity that actually owns the unit does not have market power?

MS. TIGHE: That could be an example. Yes.

MR. WEISHAAR: I think the answer to that question would depend heavily on the specifics of that particular tolling agreement to see whether there is control. It's kind of like a situation where you have a purported independent operator of a transmission system, an ISO, for example, and that is a heavily fact-intensive process and it depends on how the agreements are structured and the level of independence and control for that particular entity. Could it possibly be a means to mitigate market power or bring an entity under a screen? I think so. But I think it's a very fact-intensive and contract-dependent determination.

MS. SOLOMON: Let me add to that. I believe it is very contract-specific. I don't see how that inquiry is altered by doing either a regional analysis or an individual market analysis. It still requires determination of who has control. As you know, in the April and July orders, the issue of control is addressed very specifically. Who can determine if the supply can be withheld from the market, in effect? But there are various ways of withholding. It's not a straightforward inquiry. It's difficult. But I don't see how it's affected by which version of the inquiry you do.

MR. STIBOLT: I thought I might just add a comment because you had mentioned the complication of partnerships structures. Would that have a bearing here? I think the way I would still look at is I would just look at your partnership's share within a particular generation asset or set of assets on a net basis in terms of what your actual market share is because that can still be -- conceptually, you could still influence the profitability of that particular entity by actions elsewhere even though you don't control the particular partnership. In other words, you could be a minority partner and a number of different things. If your net market share builds up to greater than 20 percent, I think you'd still want to investigate it.

MR. RODGERS: Cliff, did you have a question?

MR. FRANKLIN: My question is for David. Let me put it in my own words and correct if I'm restating your proposal.

As I understood your statement, there are certain trading hubs that are really important and that is where the generation is bid to and that's where the demand is taken from. If you had in, for example, Puget Sound a municipality, a small town, a coop or any kind of load that had the ability to buy wholesale power, they would buy it from Mid-C and wheel it back into their area?

MR. MILLS: If they were a municipal or a coop, they would most likely be a full or partial requirements customer of Bonneville Power who would wheel that directly to the customer.

MR. FRANKLIN: So it would just be a bilateral deal within the Puget Sound area?

MR. MILLS: It would be a bilateral deal between Bonneville and municipal, basically where the municipal's distribution system and where Bonneville's system interconnect.

MR. FRANKLIN: So your concern is that a real key is how much power can you get to these trading hubs. Ignoring that one exception, your concern is that really the market power should be analyzed based on how much power can be delivered to these trading hubs?

MR. MILLS: That's correct. Yes.

MR. FRANKLIN: One other quick question for Robert.

You had made a statement, and this probably would not come under the guise of OMTR or the people that manage cases, but you made a statement that you felt it would be prudent on a monthly basis to make sure that the market power screens are, in fact, indicative of the market power potential and have it reanalyzed on a monthly basis. Was that you?

MR. WEISHAAR: I made a comment about the need for a threshold determination. That a competitive market exist before we go down the path of analyzing market-based rate authority and emphasized that that needs to be an ongoing, continuous evaluation. I did not suggest monthly or semi-semi-annually or annually. You may have heard it in that context. I'm not sure what the other panelists may have said.

MR. FRANKLIN: My question is, just real quick, there would have to be data that would have to be submitted on a cycle or periodic basic in order to make those analyses. Do you think that would be cumbersome for the utilities and demand customers and IOUs to submit that data on a site quick basis like that? Because, I assume, in order to assess the competitiveness of the market, it would take a lot of data to do that. Maybe I'm wrong. Maybe I misunderstood you. Maybe you're talking about a real simple screen or something.

MR. WEISHAAR: I'm not sure I have an answer to that. I guess the direct answer to your question of whether it's cumbersome or not cumbersome, I think needs to be answered by asking the question relative to what? Relative to the possibility that market power is exercised and customers are hurt to the tune of several billion dollars? I think you need to look at it in that context. But your statement suggesting that you're not sure what data are necessary to determine whether a competitive market exists raises some questions in my mind as to whether the threshold determination as actually been made.

MR. RODGERS: Bob, I had a question about something you mentioned in your presentation about a benchmark to establish -- as I understood it, for determining whether a market was competitive and that the Commission should continually monitor to ensure that that benchmark was being met. What is the benchmark you were referring to specifically?

MR. WEISHAAR: I didn't have a specific benchmark. If you go back to the economic's test and say what are the assumptions for a competitive market, you have ease of entry and exit. You have perfect information. You have ease of transportation. You have demand elasticity.

All of the assumptions that I think should underlie and should be the basis for a competitive market. That would be the start of a list of the standards or benchmarks that need to be analyzed to determine whether a competitive market structure exists.

MR. RODGERS: I had a few questions for David Mills.

You had mentioned in your presentation that it was your view that the control area is not the appropriate default market for the Pacific Northwest and, indeed, the entire Pacific Northwest should be regarded as the relevant geographic market for the purposes of these screens. We had a panelist from another Western utility at one of our earlier conferences and I recall his testimony being, again, that you just can't use a control area as a relevant market in the West. But he said something a little bit different from what you said.

As I recall, his point was that the scope of the market in the West can vary significantly based on both load conditions and hydro conditions. So you might have one market that's appropriate for a low hydro year and another market that's appropriate for normal hydro conditions. But, as I understood your testimony, the Commission should just always construe that the relevant market, at least for the Pacific Northwest, is the Pacific Northwest and basically the Bonneville footprint.

MR. MILLS: I was debating that with myself last night. I actually do think the Bonneville footprint would be the most appropriate. With respect to the difference between my assertion about its irrespective of hydro flow or load demand -- you know, the energy is going to be marketed some place, even in a low hydro year. Now it looks like we're going to have four years of experiencing this first-hand. And what's amazing is you may see a transition of liquidity in the low hydro year from Mid-C, maybe towards the Nevada/Oregon border as sellers bring energy from the Southwest up to the meet Northwest load. What you don't see is a large increase or an upswing in generation all of a sudden coming online from within control areas to then sell into the wholesale market.

Even of the control area, in a high peak load condition like an extreme winter peak day, our loads will go up. Our loads will double in the winter in extreme peaks. In that situation, we're buying everything we can at the published outage. So we go into a reliability mode and price is not an issue. The lights can't go out. So, at that point, generation, which had not been so dispatched for months because it's on a single-cycle turret, that will come online. But it's not at that point for economic dispatch. It's purely for reliability. But I must say I'm going to stick with, regardless of hydro flow or demand patterns, the market is more appropriate than the control area.

MR. RODGERS: One comment you made in your presentation was that even a preliminary screen failure finding by the Commission that alleges possible or potential market power concerns can adversely affect utility market participants and reduce their credit in some way. I appreciate the Commission being made aware of that point. I think that's an important point to consider. I was trying to balance that, though, or factor that in, in terms of the strong desire that I hear from many aspects of the industry. That the Commission not have a definitive market power test.

In other words, the Commission really needs to do this and it needs two parts. You have an initial indicative tests that separates the people that need a closer look and then you give those people another bite at the apple. And that's what you have to do. To have an indicative test is to have it in two parts. I think that's what that means.

So, if you do that, and there those that have problems passing the initial screen, the indicative screen, the first one -- if the Commission has, as part of its responsibility of protecting wholesale customers, don't we have an obligation to put in place the 206 procedures so as to afford refund protection to customers just in case there is ultimately found to be market power?

MR. MILLS: On a theoretical basis, I would not debate that. But I would have to share my friends from Tractebel's perspective. I operate a portfolio on a day-to-day basis, so I'm only brought in tangentially. But my mind is pretty much on the operations. I wouldn't disagree with you theoretically.

I guess what I would say is, without going too far into what I think is probably an ongoing discussion between my company and the Commission, I think we need to be very careful when we're in an arena that we're not sure that we have the right definition of market. I think that there might be -- I don't want to say a third test, but there might be a stutter step between failure to either pass the test or maybe improperly apply a test and the results of that return.

I think there might be a stutter step until we can get clarity on what the market is prior to making an announcement that an entity may have failed the test. Our market is very sensitive. Liquidity in the last three or four years in our market, especially, on the power side has gone up immensely. Most of the load-serving entities now are really only transaction at about the three- to six-month tenor. Some of the markets are now getting a one-year markets and some of the banks intimate that they're coming in for a longer tenor, but it's really tough. The market with a low number of players it doesn't take much to make the market even more squeamish.

MR. RODGERS: I'm interested in that perspective since the Commission set out with the new screens up, I'm curious, among other things, as to what Wall Street's reaction will be or has been. I haven't seen much on that issue personally. But I do know that there was a Standards & Poor's report that was picked up in the trade press back in the fall that talked about it, at least, with regard to Southern Company and Entergy. I'm particularly aware, having responsibility for entities in the southeast part of the country. The report indicated, as I recall, that there would not be a profound or real adverse effect to those utilities, even in a worst case scenario.

I recall the report mentioning that the earnings effect on one of those companies would be less than 1 percent. I'm just curious to hear your evidence sort of telling a different side of that story or painting a different picture that really there can be some significant effects. Any evidence that you or the other panelists have on that matter I'd be welcome to hear about and the written comments that are going to be able to filed after this conference.

MR. MILLS: My comments were directed at the market liquidity and the ability to transact in the wholesale market. I read that same report. To be honest, I haven't seen -- for publicly traded companies, I haven't seen a big departure in terms of their S&P rating. What I have seen, though, when there is news of a pending investigation, a series of data request or whatever might be going on from a regulatory perspective, I've seen less willingness from counter-parties to engage in long tenor transaction with the counter-party that's under investigation.

MR. O'NEILL: Can I ask a clarifying question? I'm confused. You said you were a net buyer of power. And, if your market-based rates were taken away, you'd get a negative credit?

MR. MILLS: No. That would reduce the amount of open trade credit they would extent to us.

MR. O'NEILL: When you're selling? Why would that when you're buying?

MR. MILLS: The market is very squeamish and a lot of times that type of information -- some clerk on a desk somewhere thinks, oh, this is the tip of the iceberg. There must be a lot more behind this.

MR. O'NEILL: This is an emotional reaction?

MR. MILLS: Absolutely.

MR. O'NEILL: How do we deal with emotional reactions?

(Laughter.)

MR. MILLS: I think I'm in the wrong building. I'm not sure.

(Laughter.)

MR. MILLS: I'm not qualified to answer that one.

MR. O'NEILL: Because it just confused me. I didn't know how you would tie a net buyer to a seller market power determination and then see your credit collapse.

MR. MILLS: It's purely emotional. The market reacts very quickly. I haven't seen -- it sometimes takes quite a while to work your way out of that situation through a series of conference calls, visiting with the counter-parties and reassuring them that, you know, this is not the tip of the iceberg.

MR. O'NEILL: How do we get to determining somebody who's a net buyer has market power as a seller?

MR. MILLS: I think we have a discussion underway with the Commission of that topic.

MR. RODGERS: I had a couple of questions for Mr. Wroblewski.

You mentioned some concerns about the Commission using the control area as the relevant market in certain circumstances. For some reason it reminded me of a quote from Winston Churchill that I will probably botch, but I recall him saying something to the effect that democracy is absolutely the worst form of government except for all other forms of government. The same maybe could be said about the control area approach that the Commission has to markets. Everybody seems to have criticism of it, but at the end of the day, there is not a lot of specific proposals of what would serve as a more appropriate default market for the Commission to use.

So my question to you is, if the Commission needs to be weary of using the control area as a relevant market, what should we use as the proper default relevant geographic market?

MR. WROBELWSKI: You raise a good point. The Commission is in a bind that they're trying an administratively easy way to kind of string out the people who don't have market power and keep the people who do and to look further and design appropriate mitigation.

If you look at the horizonal merger guidelines, the first that you do have to do is define your product and your geographic markets. We've always used the control market or control area as the relevant geographic market. What I would suggest is to maybe do one study of one particular area and do the type of analysis that is required under the horizonal merger guidelines defining the products, defining the various geographic markets that go with the various time periods and all the different products and see how that lines up with using the control area.

Maybe if there is kind of an empirical analysis to see whether that is the case, the control area action maybe does approximate a pretty good result 80 percent of the time and you're willing to take the fact that the other 20 percent doesn't really matter. Or it could be that 80 percent of the time the control area does not work at all and really actually has no relation to what buyers in the market -- what suppliers in the market actually face. Then I think it's incumbent upon the Commission to design something that would make more sense.

I agree with you that we as the FTC have certainly not provided additional ways in terms of don't use the control area use something else. But I think we provided advice on how to get to the right answer. Maybe to do that on a case-by-case or just one case. Just look at one case and see how it turns out and then you can make your appropriate decision from there.

MR. RODGERS: You also had mentioned that -- well, let me back up. Other panelists and other folks that have commented on the Commission's screens have indicated at times that a market share approach or a market concentration approach is not really well-suited for the electricity industry in terms of measuring market power. It may be wonderful for measuring market power in pork bellies or the automobile industry, but it doesn't really work in the electricity industry.

I'd like to ask you, assuming one has properly defined the relevant product and geographic markets, do you think that market share, market concentration analyses are helpful?

MR. WROBLEWSKI: I think they're very helpful really for one main reason -- something I wanted to jump in earlier. When you're looking at market power under the guidelines framework that the antitrust agencies use, you look at unilateral market power and you look at the possibility of coordinated interaction. Basically, two or more getting together. It ends up having the same effect as if one entity were exercising market power. So a concentration index such as HHI in properly defined markets for the different time periods and the different geographic markets, I think, is very important to look at because the end result is that there still would not be just unreasonable rates as a result of that coordinated interaction. That a concentration screen will help you assess that coordinated interaction.

When you had asked earlier, I think, Mr. Morey about could you have a non-competitive market, regional market and then have some market participants that didn't have market power, I thought that question really was only looking at the market power as a unilateral exercise, just a single firm having market power and not the possibility that those smaller firms, so to speak, could be exercising market power in a coordinated fashion.

So I do think you do need to look at both single firm and coordinated interactions. And I think a market concentrations scheme or index is probably one way to do it. And, certainly, the way the antitrust agencies look at it.

MR. RODGERS: Is it your belief, therefore, that the Commission needs to have more than one kind of screen to pick up unilateral versus collusive?

MR. WROBLEWSKI: I do believe the two screens that you have in terms of your pivotal supplier and you have your market share screen, I would rather see that market share screen be one that looked more like concentration. If you see that the one entity has 22 percent or 28 percent, I think was heard this morning, it makes a big difference as to what is the other 72 percent in that particular market? Is it one player or is it divided among many players. That 28 percent has a lot different relevance, depending upon what the complement is. And I think a concentration index will show that a little bit better than just a market share will.

MR. RODGERS: Okay. Thank you.

Cliff?

MR. FRANKLIN: I'd like to follow-up on that question. If there was somebody with 28 percent and there were a couple of others around the same and it came up over 1800 the Hoechendal-Hirschman Index --

MR. WROBLEWSKI: We just call it the HHI.

MR. FRANKLIN: Then you had a small player at 5 percent, do you determine that market concentration and they all fail? Or did you only fail the one that had 28 percent?

MR. WROBLEWSKI: What you're getting at is that HHI is really just a measure of concentration in a particular market. It's really just a guide post as to what to do. If you look under what the merger guidelines require, the framework set out in the merger guidelines, if you're above a certain level -- say, you're above a higher level than even, you then want to look at entry possibilities and other things you want to look at before you then would get to the ultimate conclusion as to whether that particular entity had market power or whether that structure was conducive to coordinated actions.

MR. FRANKLIN: I might make one other real quick comment and people can respond to it, if they wish.

Originally, when we came up with the order, the April 14th order, we talked about load pockets a lot. There was a concern for, I think, everybody. We had a lot of discussions about it. The problem that occurred, and I don't know if it's been resolved yet or if there's new data, was that, if you had a control area, that's how the data comes in -- the data command for the control area. Information about the generators in that control area that's how the data comes in.

The problem is that the control area might span two states. We might have a load pocket. It's very congestive. It has a very high potential for market power, but it's very difficult and time-intensive to get a demand figure for that load pocket and to isolate the generators and demand and transactions and anything associated with the load pocket because everything comes in on a control area basis.

I only bring that up to say I've always supported the idea of considering load pockets. But the practicality of getting the data to do some sort of analysis is very time intensive. You have to go in and parse load flow data and try to figure out which buses are in this zone and parse it out. I'm not aware of any data warehouse that segregates data by congestion zones -- just a comment.

MR. RODGERS: Dick, did you have a question?

MR. O'NEILL: Yes. The problem with the Hoechendal Index, for example, in oil pipelines, we approved market-based rates for entities with small market shares because, even though the market had maybe one supplier with

80 percent of the market, because that supplier was regulated its market power was mitigated and so there was no way, arguably, under a cost of service regime, that it could exercise market power or benefitted from coordinated interaction.

After you do the screen and mitigate the entities with market power, then the screen no longer gives you the correct indications because you've taken away their ability to exercise market power.

MR. RODGERS: Jerry?

MR. PEDERSON: Switching for a moment over to mitigation, Mr. Weishaar, you had commented earlier that in a region where, perhaps, there is no competition that some kind of cost-based cap might be applicable for that region. I was wondering if what you had in mind was a cost cap for the region itself or would that be on an individual utility-by-utility basis?

MR. WEISHAAR: I think to the extent you have an entire region that should be subject to mitigation. I think it would have to be a unit-by-unit determination as to their actual costs. How you set up the structures within that region to price electricity at wholesale, I think, is a separate issue in terms of mechanics, structure and so forth. But I think the cost determination will have to be on unit-specific basis.

MR. PEDERSON: By "unit-specific," you're talking about each generating unit within that region the cost cap would be put in.

MR. WEISHAAR: That's correct.

MR. PEDERSON: Is there some other some other way to come up with some sort of price cap or mitigation for a region?

MR. WEISHAAR: There may be. We have not given it a lot of thought.

MR. O'NEILL: If you were a buyer in that region, and we had individual unit-by-unit cost caps, would you chose to buy from the unit with the cheapest cost cap, other things being equal?

MR. WEISHAAR: All else being equal, of course.

MR. O'NEILL: Wouldn't everybody else want to buy from that unit?

MR. WEISHAAR: Sure.

MR. O'NEILL: Now we have a problem with trying to figure out how to allocate power from that unit because more people want it than the ones with the very high prices no one would want to buy from. So we have to resolve that dilemma.

MR. WEISHAAR: Yes, you would.

MR. PEDERSON: Also, Mr. Beer, earlier you had commented, to the extent the utilities failed the screens, that they should have an opportunity to come in and demonstrate to the Commission that they don't, in fact, have market power.

Currently, there a couple of ways they can do that. They can do that through the delivered price test where they come in with historical sales and transmission data. What is it about that approach that's inadequate and what other approaches should we consider?

MR. BEER: I'm not necessarily saying that it is inadequate across the board. The problem is, except for the delivered price test, it's not an inexpensive undertaking to complete that. If you have a high degree of confidence you will not be able to satisfy that, then to go through that exercise would seem to be an exercise in futility. It's not something that would be efficient to do or economical to do for anyone. So it's where I get back to this point about looking at the specifics of every single entity.

For example, LG&E, the fact that there simply is no ability within our control area because we have no contestable load. No contestable load within our control area makes it very, very difficult for us, if not impossible, to actually exercise market power. I guess the point is that there should be, if I may back up for a minute -- in going through this process, there still is a period of time where we would be under -- as I understand it, where we would be under refund liability or the potential for refunds. It's that lag period that creates the uncertainty that we would argue is unnecessary and ultimately damaging to anyone who has to go through that.

If we know at the end of the day -- in our situation we should be able to come and say, you know, we cannot exercise market power within our control area, therefore, the measure that was discussed earlier is something that is certainly one alternative. If we define our transactions that sink outside of our control area irrespective of where they originate as not being subject to any kind of cost-based regime that seems to get us where we need to be very, very quickly and eliminates that lag period where we do studies that really are unnecessary because the conclusion is known at the outset.

MR. PEDERSON: Just to be clear on that. A sale that's going outside the control area -- the situation where the utility has a market-based rate authority perhaps taken away in its control area, but it's not not to have market power in its first tier market -- what you're describing, I think, is the situation where you have a customer in a first tier market who has transmission service on that utility system and they want to make a purchase from that utility, but they want to do it at the bus of the generator because they already own the transmission, so they don't want to pay for transmission out to the edge of the control area. Is that the situation?

MR. BEER: That's accurate.

MR. PEDERSON: Thanks.

MR. O'NEILL: So the analysis would have you as not controlling that transmission because somebody else had the rights to it?

MR. BEER: Somebody else would have arranged to either have the rights to it or separately arranged for that transmission.

MR. O'NEILL: So you could make the argument here that you had no control over the transmission to get to that customer or that customer had to use to get to the generator.

MR. BEER: I think that's a fair statement.

MR. O'NEILL: In a sense, it's a different issue. If that entity already has firm transmission rights back into your system.

MR. BEER: Correct.

MR. O'NEILL: I'm trying to understand. You have no contestable load?

MR. BEER: None.

MR. O'NEILL: Meaning there's nobody you sell power to?

MR. BEER: No. Meaning there are eligible competitive wholesale customers right now within our control area because all of those that are eligible within the control area are customers of ours under long-term cost-based service contracts with five-year termination provisions.

MR. O'NEILL: Giving you cost-based rates in your control area would have no effect.

MR. BEER: It depends upon where the transaction originates. If we sell at the bus, and the transfer of title occurs at the generation bus, and you say that is a sale within our control area, even though it sinks outside of the control area, that is a problem for us.

MR. O'NEILL: I guess, if there was a showing that that entity had firm rights to get out -- firm and unequivocal rights to get out -- that may be an exception.

MR. BEER: That may be.

MR. O'NEILL: That's the story you have to tell if you fail the test.

MR. BEER: Right.

MR. O'NEILL: It seems like a pretty good story to me.

MR. RODGERS: Julie, I had a question for you.

You had mentioned as part of your presentation, and I'll paraphrase this. Correct me, if I'm wrong. But the Commission should be cautious in jumping to using cost-based mitigation, even if we were to find that there's market power concerns. One of the alternatives you suggested the Commission should use is to set price for that entity based on the prevailing market prices. But, if that market-based applicant in this hypothetical itself had market power, wouldn't that effect the prevailing market price?

MS. SOLOMON: Absolutely. The only way the proposal works is if there's a reference price that's not being affected by the "alleged market power." For example, if there's a liquid market, a liquid hub that's nearby that you can do a basis differential, perhaps, from -- if there's an ISO or an RTO next door that has an LMP at a bus, that makes sense. This is not a solution that necessarily works in all instances, but it may be an intermediate step before having to go to cost-based rates.

MR. RODGERS: That would be an advantage then of participants in an RTO or ISO market that there would be this fall back index available.

MS. SOLOMON: That's right. Although, I was really, in proposing that, I was thinking much more about an entity that was not in an RTO.

MR. RODGERS: What would be the suitable fall back index or proxy for the market price in the non-RTO/ISO market?

MS. SOLOMON: There are published prices. Platt's publishes megawatt daily prices every day. Again, if you are in a control area that's next door from MISO that is publishing a price when they're operational, and there's a way of determining a basis differential, that's potentially a price. There are published data available for many pricing points in the U.S.

MR. RODGERS: You had raised some concerns, too, about using control areas. But you felt, as I understood it, that a control area was a good default market. But that we should let applicants or intervenors define broader markets. How could the Commission make it easier to define alternative markets?

MS. SOLOMON: Perhaps, I'm more willing to deal with control areas as the default market because I have to do them so often. I think what's difficult is that there's precedent, other than an RTO, for successfully representing broader geographic market that I'm aware of. As I sit here today, I can't recall any. It may be that this similar to what Michael was saying -- a trial balloon. What is the showing that is required to successfully prove a broader market? We know what the factors are -- similar prices, lack of congestion, perhaps, lack of transmission pancaking and the like, but having been proven or accepted.

I do know there are a few places on the bus that it's considered more carefully than in the eastern interconnect.

MR. RODGERS: I think, if I'm reading the Commission order correctly, the Commission provides that kind of flexibility right now in the interim screen.

MS. SOLOMON: It does. Absolutely. It's there. I don't know how much its been exercised and I'm not aware, other than in the West, where it's been agreed upon.

MR. RODGERS: Commissioner Kelliher, did you have some questions?

COMMISSIONER KELLIHER: I have to admit some confusion on the home control area in the view of the panelists. It seems in Julie's case you're saying it's an acceptable default. The parties should be able to propose alternative geographic markets. That's what the Commission's order provides.

So far, though, I can only think of two applicants that I'm aware of that have sought some alternative geographic market. One is represented today, Puget, and Pinnacle West, I believe, even though that opportunity has been out there, to my knowledge, only two of the applicants have said, yes, we propose something other than the home control area.

Have there been more than two, Steve?

MR. RODGERS: I'm not familiar with any others.

MR. PEDERSON: I think that's fair.

COMMISSIONER KELLIHER: It looks like Steve's point that there aren't very many fans of the home control area as a proper test of the geographic market, but there's been an invitation out there to propose something else and only two instances has the invitation been taken up.k

I don't think the Commission has rejected those alternative geographic market definitions.

MS. SOLOMON: I think one can't assume that because nobody has filed one that people haven't been thinking about it. I also think, if one looks at precedents, even in the Appendix A analyses under Section 203, there are rare occurrences of any broader geographic markets being accepted. I know there was one, one time, for a merger that did not get consummated. But, other than that, I'm not aware of any. So I think there's a concern about what the hurdles for a showing is. It's not a matter of the Commission has denied your ability to make that representation.

COMMISSIONER KELLIHER: Is it the view of other panelists that we should discard the whole home control area altogether? And that we, the Commission, should either pre-define geographic market areas or have no default whatsoever and leave it up to the individual applicant to define a geographic market?

MR. MOREY: Let me take a stab at that.

I have been one who's been critical of using the control area as a default. However, I don't think you should necessarily abandon that. I think the discussion this morning, and on this panel, as indicated a recognition that the control area may well correspond or be a reasonable proxy where it corresponds well to what you would see as the transmission limited region. If there were no further constraints within the limits of that control area, it might well be a reasonable approximation.

In other cases, again, the area could be larger for any individual applicant for the authority to come in with a proposal for a larger area. It's a risky proposition to go through. So I think they're waiting, perhaps, for the Commission to make a move. As Julie is suggesting, perhaps, a kind of test case.

COMMISSIONER KELLIHER: Let me as a question, Mr. Morey and I think, Mr. Weishaar had a difference of opinion on, if a certain geographic market or regional market is deemed non-competitive. Let's assume there is some number, one or two dominant sellers, and there's other sellers that are not dominant. I think Mr. Morey said that the dominant sellers should be denied market-based rate authorization, but not the non-dominant sellers.

I thought Mr. Weishaar said the reverse. If the market is non-competitive, no one should have market-based rates in the entire region. Is that your view?

MR. MOREY: I think you characterized my view correctly. I won't speak for Bob.

MR. WEISHAAR: I'm not sure, under the legal precedent, that, if you have a finding that a competitive market does not exist, you can get to a point of granting market-based rate authority.

COMMISSIONER KELLIHER: We usually look at from the point of view of an individual seller. Can a seller charge just and reasonable rates? And the other inquiry is, can they exercise market power? It's reasonable to look at it from the seller's point of view, concluding the market may not be competitive. But the seller can exercise generation market power.

MR. WEISHAAR: I understood your question to posit a hypothetical of competitive market doesn't exist in a particular region, can any entity within that region have market-based rate authority. Under that hypothetical where a competitive market doesn't exist, I don't think you can get to the next step of granting market-based rate authority because of the absence of competitive conditions.

COMMISSIONER KELLIHER: Under your scenario, wouldn't you see less entry into that market -- one of the conditions that you have laid out as necessary a competitive market? If no one building the power plant can get market-based rates, wouldn't fewer people build power plants?

MR. WEISHAAR: That issues needs to be addressed. All I'm saying is that, in our reading of the appellant precedent, in the absence of a competitive market, the market-based rate authority is not permissible. How we deal with new entry, resource adequacy, et cetera, et cetera, I think all needs to be addressed.

Your question regarding the definition of the relevant market and whether we go ISO, RTO, level or a control area level, I think, inevitably, as Mr. Franklin suggested, you get to the issue of load pockets. You may not get it at the stage of analyzing market-based rate authority. But, as we've seen over the last two or three years, you get to those determinations whether it's in the form of frequently mitigated units or retirement issues or reliability must run type agreements. Inevitably, you get to the data.

Intensive analysis of load pocket issues -- I think our position is that because you have the administrative burden at some point, from a customer protection perspective, it's better to do it sooner rather than later.

COMMISSIONER KELLIHER: Thank you.

I have a question on joint operating agreements and how the Commission should consider that. If there's a joint operating agreement between two RTOs, should we consider the geographic market to be both RTOs?

MR. MOREY: Once again, you've got to consider whether there still exist a seam. There may be a joint operating agreement, but there still maybe seams, issues and factors that affect the relevant size of the geographic market. I don't think that we, by virtue of a joint operating agreement, say, between PJM and MISO, for example, that that necessarily eliminates congestion, transmission constraints or limits the size of the market in a particular period or season or whatever. I think you still have to consider those issues within the context of an ISO or RTO, notwithstanding the joint operating agreements.

COMMISSIONER KELLIHER: Two questions for Mr. Beer.

In your statement you said that currently there is de jure mitigation by state commissions, presumably, of wholesale power sellers to exercise generation market power. That the Commission should take account of mitigation that is imposed by state commissions. And I'm guessing, on someone's ability to exercise generation market power in the wholesale markets. I don't understand mitigation could be imposed by state commissions in those sales.

MR. BEER: I guess what I was referring to in that statement wasn't necessarily the ability to regulate any aspect of wholesale transactions. but rather the use to which generation is put by the utility as part of the integrated resource planning and the least cost planning process.

We construct generation solely for the purpose of serving native load and that has to be satisfied. The Commission has to be satisfied that that is the least cost alternative, vis-a-vis, any other independent alternative to that generation. So it's a determination that we haven't been exercising any kind of power to exclude others from being able to participate in that process. It's that we've satisfied our commission that this is the least cost alternative for installing this capacity.

COMMISSIONER KELLIHER: It's mitigation that has nothing to do with your role as a wholesale power seller.

MR. BEER: Right.

COMMISSIONER KELLIHER: Finally, I'm curious about your wholesale sales that take place within your home control area. You said they're under long-term contracts with five-year terminations clauses. Are those cost-bases sales?

MR. BEER: Those are cost-based contracts.

COMMISSIONER KELLIHER: Thank you very much.

MR. RODGERS: Jerry has a few more questions, then we're going to open the floor up to questions from the audience. So, if any of you are interested in asking any questions or making comments, you can come up to the microphones at either end.

MR. PEDERSON: Peter, actually, I just have an amendment to statement made a moment ago regarding whether the Commission had ever approved a market that's larger than a single control area. On the December 15th agenda, there was a case by Consumers. My recollection is that Consumers we used the next control area, which is larger than its single control area. That was approved by the Commission. I will verify that later, but that is my recollection.

MR. RODGERS: Are there any questions from the audience?

Please introduce yourself, say who you're with, please.

MR. McINTYRE: Kevin McIntyre with Jones Day here i n Washington -- a question for Mr. Weishaar.

I believe I understood you to say that in a market where market power is found to exist the only statutorily permissible mitigation would be the imposition of cost-based rate caps. Did I get that right.

MR. WEISHAAR: I said you have to get back to cost. Cost is certainly dispatched. The only totally permissible means of achieving just and reasonable rates -- I'd have to go back and look at my actual statement to determine whether or not I agree with your characterization.

MR. McINTYRE: Are you able to say whether it's your view that some other form of mitigation would be statutorily permissible?

MR. WEISHAAR: My precise statement was market power mitigation measures must be tied in some way to the sellers actual cost and that any deviation from cost could occur, but under the Farmer's Union precedent must be thoroughly explained and justified and targeted at a level that is no more than needed.

MR. McINTYRE: So, if I understand you correctly then, some of the other possible forms of mitigation such as, for example, the benchmarks discussed by Dr. Solomon and the use of a price index that's published or some sort of auction procedures, those types of procedures, if not tied to actual costs, would statutorily impermissible and therefore not available to the Commission.

MR. WEISHAAR: As long as they met the Farmer's Union standard for deviation from cost, I think they would be permissible. But that is the relevant standard.

MR. McINTYRE: Thank you.

MR. RODGERS: Are there any other questions from the audience. Please come forward.

MR. FOX-PENNER: Peter Fox-Penner from the Brattle Group. I've done a few of these applications under both the old and new tests. I just have a comment to make in response to the Commissioner's questions about control areas and all of your excellent comments today. There is no question that the data tended to come in on a control area basis. I think that makes it the logical locus of examination in the first instance. But I do believe that there are ways that we practitioners look for markets smaller than control areas and look for markets bigger than them.

I just want to make sure everyone has in their mind the difference between the fact that there's sort of a logical default because the data come in that way and the ability to do analyses to show that the market's bigger or smaller than control areas, I believe that the Commission now allows for that. But I hope you will clarify that and continue to really allow that so that applicants can prove or intervenors can prove that markets are either bigger or smaller than control areas and that that's not just an empty option.

Thank you very much.

COMMISSIONER KELLY: Peter, does it matter whether it's done at the screening time or afterwards with the delivered price test.

MR. FOX-PENNER: I would prefer that it be allowed at the screening stage. If applicants are willing to put in that amount of work because it's not trivial to define markets. I'm sure the FTC will agree with us on that. But I would allow it at the screening stage, provided that the work is done thoroughly.

COMMISSIONER KELLY: Thank you.

MR. RODGERS: Thank you, Peter. Any other questions from the audience.

(No response.)

MR. RODGERS: Before we adjourn, I want to mention that we will reconvene tomorrow morning at 9:00, contrary to the supplemental notice that went out, which had the conference ending about 4:30 tomorrow. We're going to end the conference at 1:00 tomorrow, so there will be a break mid-morning between the two panels that we're going to have. One running approximately from 9:00 to 11:00 and other one running approximately from 11:15, 11:20 until 1:00. The conference will end at 1:00 o'clock tomorrow. Reconvene at 9:00.

Thank you very much panelists for an excellent job. We appreciate it.

(Whereupon, at 3:40 p.m., the above-entitled matter was adjourned, to reconvene at 9:00 a.m. on Friday, January 28, 2005.)